WHITING PETROLEUM CORP
Form 10-K
February 23, 2012

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, 2011

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:

(Title of Class)	(Name of each exchange on which registered)
6.25% Convertible Perpetual Preferred Stock, $0.001 par value	New York Stock Exchange
Common Stock, $0.001 par value	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None.

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.YesT 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 TNo £

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.T

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, 2011: $6,693,638,388.

Number of shares of the registrant's common stock outstanding at February 15, 2012: 117,468,023 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2012 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 and other liquid hydrocarbons.

“Bcf” One billion cubic feet of natural gas.

“BOE” One stock tank barrel equivalent of oil, calculated by converting natural gas volumes to equivalent oil barrels at a ratio of six Mcf to one Bbl of oil.

“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.

“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.

“FASB” Financial Accounting Standards Board.

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

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

“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.

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"PDNP" Proved developed nonproducing reserves.

"PDP" Proved developed producing reserves.

"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.

"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 Securities and Exchange Commission ("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 footnote (1) 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

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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.

"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.

"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.

"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.

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PART I

Item 1. Business

Overview

We are an independent oil and gas company engaged in acquisition, development, exploitation, production and exploration activities primarily in the Rocky Mountains, Permian Basin, Mid-Continent, Michigan and Gulf Coast 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, 2011, our estimated proved reserves totaled 345.2 MMBOE, representing a 13% increase in our proved reserves since December 31, 2010. Our 2011 average daily production was 67.9 MBOE/d and implies an average reserve life of approximately 13.9 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2011, their corresponding pre-tax PV10% values, and our fourth quarter 2011 average daily production rates, as well as our company's total standardized measure of discounted future net cash flows as of December 31, 2011:

	Proved Reserves (1)						
Core Area	Oil (2) (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil (2)		Pre-Tax PV10% Value (3) (In millions)	4th Quarter 2011 Average Daily Production (MBOE/d)
Rocky Mountains	132.2	162.3	159.2	83	%	$ 4,157.1	44.4
Permian Basin	122.5	38.1	128.8	95	%	2,011.6	13.4
Mid-Continent	37.9	19.9	41.2	92	%	1,046.7	8.4
Michigan	3.4	41.7	10.3	33	%	115.0	2.8
Gulf Coast	1.8	23.0	5.7	32	%	74.3	1.7
Total	297.8	285.0	345.2	86	%	$ 7,404.7	70.7
Discounted Future Income Taxes	-	-	-	-		(2,132.2)	-
Standardized Measure of Discounted Future Net Cash Flows	-	-	-	-		$ 5,272.5	-

(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, 2011, pursuant to current SEC and FASB guidelines.

(2) Oil includes natural gas liquids.

(3) 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 and natural gas reserves.

While historically we have grown through acquisitions, we are increasingly focused on a balance between exploration and development programs and 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;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows;
- seeking property acquisitions that complement our core areas; and
- allocating a portion of our capital budget to leasing and exploring prospect areas.

During 2011, we incurred $1,903.3 million in exploration, development and total acquisition expenditures, including $1,653.2 million for the drilling of 284 gross (135.0 net) wells. Of these new wells, 130.5 (net) resulted in productive completions and 4.5 (net) were unsuccessful, yielding a 97% success rate.

Our current 2012 capital budget is $1,600.0 million, and included in this amount is approximately $136.2 million in acreage acquisition costs. The 2012 capital budget of $1,600.0 million represents a 13% decrease from the $1,840.2 million in exploration, development and acreage expenditures we incurred in 2011. We expect to fund substantially all of our 2012 capital budget using net cash provided by operating activities, which has increased primarily in response to the higher oil prices experienced throughout 2011 and continuing into the first part of 2012, as well as in response to higher crude oil production volumes.

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" for more information on these acquisitions and divestitures.

2011 Acquisitions. On July 28, 2011, we completed the acquisition of approximately 23,400 net acres and one well in the Missouri Breaks prospect in Richland County, Montana for an unadjusted purchase price of $46.9 million.

On March 18, 2011, we formed Sustainable Water Resources, LLC ("SWR") with an unrelated third party to develop a water project in the state of Colorado. We 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, we completed the acquisition of 6,000 net undeveloped acres and additional working interests in the Pronghorn field in Billings and Stark Counties, North Dakota, for an aggregate purchase price of $40.0 million.

2011 Divestitures. On September 29, 2011, we sold our 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. We used the net proceeds from the property sale to repay a portion of the debt outstanding under our credit agreement.

2010 Acquisitions. In September 2010, we acquired operated interests in 19 producing oil and gas wells, undeveloped acreage, and gathering lines, all of which are located on approximately 20,400 gross (16,100 net) acres in Weld County, Colorado. The aggregate purchase price was $19.2 million; substantially all of which was allocated to the oil and gas properties and acreage acquired.

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In August 2010, we acquired oil and gas leasehold interests covering approximately 112,000 gross (90,200 net) acres in the Montana portion of the Williston Basin for $26.0 million. The undeveloped acreage is located in Roosevelt and Sheridan counties.

2010 Divestitures. We did not have any significant divestitures during the year ended December 31, 2010.

Business Strategy

Our goal is to generate meaningful growth in our net asset value per share of proved reserves by acquisition, exploitation and exploration of oil and gas projects with attractive rates of return on capital employed. To date, we have pursued this goal through both the acquisition of reserves and continued field development in our core areas. Because of our extensive property base, we are pursuing several economically attractive oil and gas opportunities to exploit and 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, 2011, we have assembled approximately 1,104,500 gross (681,500 net) acres in the Williston Basin located in Montana and North Dakota. We currently have 21 drilling rigs operating in the Williston Basin. As of February 1, 2012, there were 292 operated wells producing, 46 operated wells being completed or awaiting completion, 16 wells being drilled and 31 wells shut-in awaiting workover operations. The Sanish field, located in Mountrail County, North Dakota, was the focus of our development activities during 2011. During the fourth quarter of 2011, we completed 19 gross operated wells in our Sanish field, bringing the total number of producing wells in the field to 218. Our Lewis & Clark/Pronghorn prospects are located primarily in Stark and Billings counties, North Dakota where we have assembled approximately 385,700 gross (256,300 net) acres as of December 31, 2011. In December 2011, we completed and commissioned our gas processing plant located south of Belfield, North Dakota, which will have a processing capacity of 30 MMcf/d and which will primarily process production from the Pronghorn area. In January 2012, we completed construction on an oil terminal and a seven-mile oil transmission line to allow for the delivery of oil production from Pronghorn into the Bridger Four Bears oil transmission system. The completion of this terminal will reduce our transportation costs per barrel and make the development of this prospect more economical.

Developing and Exploiting Existing Properties. Our existing property base and our acquisitions over the past five years have provided us with numerous low-risk opportunities for exploitation and development drilling. As of December 31, 2011, we have identified a drilling inventory of over 2,200 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 non-proved reserves on which we have spent significant time evaluating the costs and expected results. Additionally, we have several 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 two large oil fields, the Postle field, located in the Oklahoma Panhandle, and the North Ward Estes field, located in the Permian Basin of West Texas. We have experienced significant production increases to date in these fields through the use of secondary and tertiary recovery techniques, and we anticipate such production increases at the North Ward Estes field to continue over the next four to five years. In these fields, we are actively injecting water and CO_2 and executing extensive re-development, drilling and completion operations, as well as enhanced gas handling and treating capability.

Growing Through Accretive Acquisitions. From 2004 to 2011, we completed 16 separate acquisitions of producing properties for estimated proved reserves of 230.9 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, negotiating and closing purchases and managing acquired properties. We intend to selectively pursue the acquisition of properties complementary to our core operating areas.

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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 and internally generated cash flow, 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. 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 effective application of new technologies.

Balanced, Long-Lived Asset Base. As of December 31, 2011, we had interests in 9,933 gross (3,806 net) productive wells across approximately 1,177,100 gross (607,500 net) developed acres in our five core geographical areas. We believe this geographic mix of properties and organic drilling opportunities, combined with our continuing business strategy of acquiring and exploiting properties in these areas, presents us with multiple opportunities in executing our strategy because we are not dependent on any particular producing regions or geological formations. Our proved reserve life is approximately 13.9 years based on year-end 2011 proved reserves and 2011 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 31 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated detailed 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 7,220 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. With the acquisition of the Postle and North Ward Estes properties, we have assembled a team of 12 professionals averaging over 23 years of expertise managing CO_2 floods. This provides us with the ability to pursue other CO_2 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 our in-house rock analysis laboratory. This state-of-the-art facility includes two scanning electron microscopes (“SEM”), and these SEMs enable rapid turnaround analysis of drilling or cored wells designed to support “real-time” drilling and completion decisions. These SEMs also allow us to quantify porosity networks, which in turn helps our staff comparatively evaluate producing zones in present and future plays under consideration. In addition, having SEMs in-house allows our team of experts to analyze samples more rapidly than an outside service company would and with the full operational context that only full-time employees possess, while protecting our proprietary data. Furthermore, we have established a two-room core layout facility capable of displaying several hundred feet of core slabs under plain or ultraviolet light. The ability for multidisciplinary groups such as geoscientists, operations personnel, reservoir engineers, drilling engineers and senior management to conveniently discuss technical issues over the displayed cores has helped us become a leader in tight oil play exploration and development.

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In 2011, we successfully implemented the first 40-stage fracture stimulation treatment utilizing sliding sleeve technology and have used three 40-stage systems to date. We are also testing systems that simulate a plug and perf type fracture stimulation treatment using sliding sleeve technology. These systems have the potential to provide the proppant distribution of a plug and perf type job with the efficiency of the continuous pumping associated with sliding sleeve technology. Depending on equipment and well performance, the use of this technology could be expanded in our operations.

Over the past two and a half years, our use of the "Drill Well on Paper" ("DWOP") optimization process to perform step-by-step analysis of the drilling programs in the Bakken and Three Forks formations in North Dakota has allowed us to reduce drill times from 38 days to 17 days per well in the Sanish Field and from 35 days to 26 days per well in other fields throughout North Dakota. As post-DWOP drill times in North Dakota have stabilized at these reduced rates, drilling procedures are being modified to utilize "Reaming While Drilling" ("RWD") and pad drilling technologies to further reduce drilling time and cost per well. RWD technology is expected to eliminate the rig time associated with a separate reamer run after total depth is reached to condition the wellbore before production liner installation. We have also implemented pad drilling technology to reduce surface disturbance and rig mobilization costs by drilling two or three wells from a single drilling location.

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Proved, Probable and Possible Reserves

Our estimated proved, probable and possible reserves as of December 31, 2011 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)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Estimated Future Capital Expenditures (In millions)
PDP	91.7	107.0	109.5	69 %	
PDNP	1.9	1.8	2.2	1 %	
PUD	38.6	53.5	47.5	30 %	
Total Proved	132.2	162.3	159.2	100 %	$ 848.2
Total Probable	24.7	133.5	46.9		$ 749.4
Total Possible	59.2	150.0	84.3		$ 1,420.1
Permian Basin:					
PDP	53.2	26.3	57.6	45 %	
PDNP	18.3	3.7	18.9	15 %	
PUD	51.0	8.1	52.3	40 %	
Total Proved	122.5	38.1	128.8	100 %	$ 1,011.1
Total Probable	36.9	53.0	45.8		$ 650.5
Total Possible	101.9	8.9	103.3		$ 1,077.7
Mid-Continent:					
PDP	32.2	18.7	35.3	86 %	
PDNP	1.1	0.8	1.2	3 %	
PUD	4.6	0.4	4.7	11 %	
Total Proved	37.9	19.9	41.2	100 %	$ 86.6
Total Probable	5.9	1.7	6.1		$ 215.0
Total Possible	0.1	-	0.1		$ -
Michigan:					
PDP	2.0	29.2	6.8	66 %	
PDNP	1.0	7.4	2.2	21 %	
PUD	0.4	5.1	1.3	13 %	
Total Proved	3.4	41.7	10.3	100 %	$ 17.2
Total Probable	2.0	9.9	3.7		$ 32.3
Total Possible	0.7	8.0	2.0		$ 13.7
Gulf Coast:					
PDP	1.7	13.7	4.0	70 %	
PDNP	0.1	2.7	0.6	11 %	
PUD	-	6.6	1.1	19 %	
Total Proved	1.8	23.0	5.7	100 %	$ 19.7
Total Probable	1.3	12.8	3.4		$ 35.7
Total Possible	2.2	20.3	5.6		$ 71.6

Total Company:							
PDP	180.8	194.9	213.2	62	%		
PDNP	22.4	16.4	25.1	7	%		
PUD	94.6	73.7	106.9	31	%		
Total Proved	297.8	285.0	345.2	100	%	$	1,982.8
Total Probable	70.8	210.9	105.9			$	1,682.9
Total Possible	164.1	187.2	195.3			$	2,583.1

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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. During 2011, sales to Plains Marketing LP and Shell Trading Company accounted for 27% and 13%, respectively, of our total oil and natural gas sales. During 2010, sales to Shell Western E&P, Inc., Plains Marketing LP and Nexen Pipeline USA, Inc. accounted for 17%, 16% and 13%, respectively, of our total oil and natural gas sales. During 2009, sales to Shell Western E&P, Inc., Plains Marketing LP and EOG Resources, Inc. accounted for 18%, 15% and 13%, respectively, of our total oil and natural gas sales. 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.

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 in the operation of our business.

We believe that we have satisfactory title to or rights in all of our producing properties. As is customary in the oil and gas industry, minimal 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 capital available for investment 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 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 natural gas liquids can currently be made at uncontrolled 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 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. The natural gas industry historically has been very 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 PIPES Act of 2006 and the Pipeline Safety, Regulatory Certainty and Job Creation Act of 2012. The Pipeline and Hazardous Material Safety Administration ("PHMSA"), an agency with the DOT, enforces regulations on interstate natural gas transportation. Intrastate natural gas transportation is subject to enforcement by state regulatory agencies. 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 under 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 natural gas liquids 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. 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 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 FERC and it is currently the subject of a petition for review filed in the District of Columbia Circuit Court of Appeals. The outcome of the case will have a similar impact on all oil pipeline operators. 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.

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. 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 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 at which 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, gas and natural gas liquids within its jurisdiction.

Some of our offshore operations are conducted on federal leases that are administered by the Bureau of Ocean Energy Management ("BOEM") (formerly Minerals Management Service and Bureau of Ocean Energy Management, Regulation, and Enforcement). 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 $33.0 million as of December 31, 2011. Whiting is therefore required to comply with the regulations and orders issued by 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 approval 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, BOEM could require us to suspend or terminate our operations on a federal lease.

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 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.

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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.

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 substantial compliance 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 ("CERCLA" or "Superfund") and comparable state laws impose liability, without regard to fault or the legality of the original conduct, on certain classes of persons that contributed to the release of a "hazardous substance" into the environment. These persons include the "owner" or "operator" of a disposal site or sites where a release occurred and entities that disposed or arranged for the disposal of the hazardous substances found at the site. Under CERCLA, such persons may be subject to strict, 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 the hazardous substances released into the environment. In the course of our ordinary operations, we may generate material that may fall within CERCLA's definition of a "hazardous substance". 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.

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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, hydrocarbons or other materials may have been disposed or released on, under, or from the properties owned or leased by us or on, under, or from other locations where these hydrocarbons and materials have been taken for disposal. In addition, many of these owned and leased properties have been operated by third parties whose management and disposal of hydrocarbons and materials were 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 material itself may be subject to CERCLA and analogous state laws. Under these laws, we could be required:

- 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; or
- to perform remedial operations to prevent future contamination, including the plugging and abandonment of wells drilled and left inactive by prior owners and operators.

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”) is the principal federal statute governing the treatment, storage and disposal of hazardous wastes. RCRA imposes stringent operating requirements and liability for failure to meet such requirements on a person who is either a “generator” or “transporter” of hazardous waste or on an “owner” or “operator” of a hazardous waste treatment, storage or disposal facility. RCRA and many state counterparts specifically exclude from the definition of hazardous waste “drilling fluids, produced waters, and other wastes associated with the exploration, development, or production of crude oil, natural gas or geothermal energy”. Therefore, a substantial portion of RCRA’s requirements do not apply to our operations because we generate minimal quantities of these hazardous wastes. However, it is possible that certain 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. 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 of 1972, or the Clean Water Act ("CWA"), imposes restrictions and controls on the discharge of produced waters and other pollutants into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. CWA and certain state regulations prohibit the discharge of produced water, sand, drilling fluids, drill cuttings, sediment and certain other substances related to the oil and gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit.

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. CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. 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 (the "CAA"), as amended, 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, on July 28, 2011, the EPA proposed rules that would establish new air emission controls for oil and natural gas production operations. Specifically, the EPA's proposed rule package 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 would require the application of reduced emission completion techniques for completion of newly drilled and fractured wells in addition to existing wells that are refractured. The proposed rules also would establish specific requirements regarding emissions from compressors, dehydrators, storage tanks and other production equipment. The EPA will receive public comment and hold hearings regarding the proposed rules and must take final action on them by April 3, 2012. If finalized, 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.

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Hydraulic Fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons, particularly natural gas, from tight formations. Hydraulic fracturing has been utilized in the completion of wells we have drilled, and we expect it will also be used in the future. The process involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and gas commissions. However, the EPA recently took the position that hydraulic fracturing operations using diesel are subject to regulation under the Underground Injection Control program of the Safe Drinking Water Act as Class II wells and has commenced drafting guidance for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel. Industry groups have filed suit challenging the EPA's recent decision. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and final results by 2014. Moreover, the EPA recently announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 2014 that such wastewater must meet before being transported to a treatment plant. Other federal agencies are also examining hydraulic fracturing, including the DOE, the U.S. Government Accountability Office and the White House Council for Environmental Quality. The U.S. Department of the Interior is also considering regulation of hydraulic fracturing activities on public lands. In addition, the Fracturing Responsibility and Awareness of Chemicals Act ("FRAC Act") has been introduced in Congress 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 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) 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 and potential increases in costs. Further, at least three local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such legal requirements could make it more difficult or costly for us to perform hydraulic fracturing activities. Moreover, we believe that enactment of legislation regulating hydraulic fracturing at the federal level may have a material adverse effect on our business.

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 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.

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, 2011, we had 692 full-time employees, including 32 senior level geoscientists and 64 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 Report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, 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.

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 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:

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- 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 threats by Iran to block the Strait of Hormuz;
- 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 recent announcement of the planned reversal of the Seaway pipeline from Cushing, Oklahoma to the Gulf Coast 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 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 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 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.

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 development, exploitation, production and exploration 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:

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- delays imposed by or resulting from compliance with regulatory requirements;
- 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 and natural gas prices;
- pipeline takeaway and refining and processing capacity; and
- title problems.

Federal and state 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 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 in the completion of our wells in Colorado, Michigan, Montana, North Dakota and Texas, and we expect it will also be used in the future. The process is typically regulated by state oil and gas commissions. However, the EPA has asserted federal regulatory authority over hydraulic fracturing involving diesel under the Safe Drinking Water Act's Underground Injection Control Program and has commenced drafting guidance for permitting authorities and the industry regarding the process for obtaining a permit for hydraulic fracturing involving diesel. Industry groups have filed suit challenging the EPA's recent decision.

At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with initial results of the study anticipated to be available by late 2012 and final results by 2014. Moreover, the EPA recently announced in October 2011 that it is also launching a study regarding wastewater resulting from hydraulic fracturing activities and currently plans to propose standards by 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 is also considering regulation of hydraulic fracturing activities on public lands. In addition, legislation called the FRAC Act has been introduced in Congress 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 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) 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, at least three local governments in Texas have imposed temporary moratoria on drilling permits within city limits so that local ordinances may be reviewed to assess their adequacy to address such activities. 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 or regulations that significantly restrict or otherwise impact hydraulic fracturing are passed by Congress or adopted in the states 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.

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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 CO2 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 CO2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO2. Under our CO2 contracts, if the supplier suffers an inability to deliver its contractually required quantities of CO2 to us and other parties with whom it has CO2 contracts, then the supplier may reduce the amount of CO2 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 CO2 available to us, we may not have sufficient CO2 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 CO2 as part of our enhanced recovery techniques.

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, 2011, proved undeveloped reserves comprised 41% of the North Ward Estes field’s total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $718.1 million at the North Ward Estes field as of December 31, 2011. This field encompasses 42% 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 which 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 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 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 $3.2 million impairment write-down during 2011 for the partial impairment of producing properties, primarily natural gas, in California and Michigan. 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.

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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 and natural gas, including differentials, production and development costs, gathering and transportation costs, severance and excise taxes, capital expenditures and availability of funds.

Therefore, estimates of oil and natural gas reserves are inherently imprecise. Actual future production, oil and natural gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves 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, 2011 would have decreased from $5,272.5 million to $5,266.7 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, 2011 would have decreased from $5,272.5 million to $5,189.5 million.

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

Our net income and cash flows will depend upon, among other things, oil, natural gas and natural gas liquids production and prices and the costs incurred to exploit oil and natural gas reserves. Drilling, production or transportation accidents that temporarily or permanently halt the production and sale of oil, natural gas and natural gas liquids 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 and state legislative and regulatory initiatives relating to hydraulic fracturing..." later in these Risk Factors for a discussion of the uncertainty involved in the practice of hydraulic fracturing. In addition, curtailments or damage to pipelines used to transport oil, natural gas and natural gas liquids production to markets for sale could decrease revenues or increase transportation expenses. Any such curtailment or damage to the gathering systems could also require finding alternative means to transport the oil, natural gas and natural gas liquids production, which alternative means could result in additional costs that will have the effect of increasing transportation expenses.

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Also, drilling, production and transportation of hydrocarbons bear an 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, 2011, we had $780.0 million in borrowings and $1.4 million in letters of credit outstanding under Whiting Oil and Gas Corporation's credit agreement with $718.6 million of available borrowing capacity, as well as $600.0 million of senior subordinated notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's 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;
- making us vulnerable to increases in interest rates, because debt under Whiting Oil and Gas Corporation's credit agreement is subject to certain rate variability; and
- potentially limiting our ability to pay dividends in cash on our convertible perpetual preferred stock.

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 will 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 Corporation's 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 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 Corporation's 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.

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

The indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's 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 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 Corporation's 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 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter 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 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 Corporation's 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 subordinated notes or Whiting Oil and Gas Corporation's 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 available further funds. Furthermore, if we are in default under the agreements governing our indebtedness, we will not be able to pay dividends on our capital stock.

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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 and internally generated cash flows. We intend to finance future capital expenditures with cash flow from operations 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 bank 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.

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.

The global recession and tight financial markets may have impacts on our business and financial condition that we currently cannot predict.

The current global recession and tight credit financial markets may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection.

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:

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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 related to future acquisitions.

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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 such as CO_2 for production which could become subject to shortage and increasing costs. Shortages of field personnel, high cost 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.

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, 2011, we had identified a drilling inventory of over 2,200 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, 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 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 2010, we recorded a $5.8 million non-cash charge for the impairment of unproved properties in the central Utah Hingeline play. 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.

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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 2011, we completed 16 separate acquisitions of producing properties with a combined purchase price of $1,900.3 million for estimated proved reserves as of the effective dates of the acquisitions of 230.9 MMBOE. The successful acquisition of producing properties requires assessments 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
- potential environmental and other liabilities.

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.

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 forward sales contracts, primarily costless collars, placed with major financial institutions. As of January 31, 2012, we had contracts, which include our 24.2% share of the Whiting USA Trust I hedges, covering the sale of between 983,477 and 984,054 barrels of oil per month and between 30,640 and 33,381 MMBtu of natural gas per month for all of 2012. All our oil hedges will expire by November 2013, and all our natural gas hedges will expire by December 2012. See "Quantitative and Qualitative Disclosure about Market Risk" in Item 7A of this Annual Report on Form 10-K for pricing 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 transaction 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.

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Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that were previously designated as cash flow hedges, and we elected to discontinue hedge accounting prospectively. As such, subsequent to March 31, 2009 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.

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 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. 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;
- 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.

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

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.

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, 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 and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends 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.

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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.

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, as a result of the explosion and fire on the Deepwater Horizon drilling rig in April 2010 and the release of oil from the Macondo well in the Gulf of Mexico, there has been a variety of governmental regulatory initiatives to make more stringent or otherwise restrict oil and natural gas drilling operations in certain locations. 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.

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

On December 15, 2009, the U.S. Environmental Protection Agency (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.

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 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 development, exploitation and exploration 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 exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, 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; J. Douglas Lang, 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.

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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 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 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.

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 February 2011, President Obama's Administration released its proposed federal budget for fiscal year 2012 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 certain U.S. production activities; and
- an extension of the amortization period for certain geological and geophysical expenditures.

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The 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.

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Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties and Projects

Rocky Mountain Region

Our Rocky Mountain operations include assets in the states of North Dakota, Montana, Colorado, Utah, Wyoming and California. As of December 31, 2011, our estimated proved reserves in the Rocky Mountain region were 159.2 MMBOE (83% oil), which represented 46% of our total estimated proved reserves and contributed 47.4 MBOE/d of average daily production in December 2011.

Sanish Field. Our Sanish area in Mountrail County, North Dakota encompasses approximately 108,800 gross (66,500 net) acres. Net production in the Sanish field averaged 22.9 MBOE/d for the fourth quarter of 2011, but ended the quarter averaging 25.7 MBOE/d in December 2011. This compares to production of 24.1 MBOE/d from the Sanish field for the third quarter of 2011. During the fourth quarter of 2011, we completed 19 operated wells, bringing the total number of producing wells in the field to 218. As of February 1, 2012, we had 33 service units active in the Williston Basin. These service units have reduced the number of shut-in wells in Sanish field from 66 as of October 22, 2011 to 31 as of February 1, 2012. We expect to continue to reduce the number of shut-in wells awaiting service work in this field during the first quarter of 2012.

In order to process the produced gas stream from the Sanish wells, we constructed and brought on-line the Robinson Lake gas plant. In December 2010, we added additional equipment which brought the plant's processing capacity to 90 MMcf/d. However, inlet compression currently only provides for 60 MMcf/d throughput. In April 2011, we added fractionation equipment which allows us to produce propane and butane for sale in the local market. We intend to further expand the plant in order to increase our inlet capability to 90 MMcf/d in the third quarter of 2012.

Outside of our Sanish field we have assembled lease positions on eight separate prospects in the Williston Basin. Seven of these prospects target the Bakken and Three Forks formations, and one prospect, Big Island, targets the Red River formation. During 2011, our efforts were focused on the drilling of delineation wells on these prospects. Our focus in 2012 will be on the development of the Lewis & Clark/Pronghorn prospects.

Lewis & Clark/Pronghorn. Our Lewis & Clark/Pronghorn prospects 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. Net production in the Lewis & Clark/Pronghorn prospects averaged 5.9 MBOE/d in the fourth quarter of 2011, representing a 48% increase from 4.0 MBOE/d in the third quarter of 2011. We currently have six drilling rigs operating in the Pronghorn prospect and two drilling rigs operating in the Lewis & Clark prospect. In December 2011, we completed and commissioned the gas processing plant located south of Belfield, North Dakota, which will have a processing capacity of 30 MMcf/d and which will primarily process production from the Pronghorn area. Currently, there is inlet compression in place to process 24 MMcf/d. In January 2012, we completed construction on an oil terminal and a seven-mile oil transmission line to allow for the delivery of oil production from the Pronghorn into the Bridger Four Bears oil transmission system. The completion of this terminal will reduce our transportation costs per barrel and make the development of this prospect more economical.

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We have begun utilizing pad drilling at our Sanish field and our Lewis & Clark/Pronghorn prospects, drilling two or three wells from each pad.

Hidden Bench/Tarpon. Our Hidden Bench and Tarpon prospects in McKenzie County, North Dakota target the Bakken and Three Forks formations and encompass approximately 59,900 gross (29,400 net) acres and 8,100 gross (6,300 net) acres, respectively, as of December 31, 2011. Net production at Hidden Bench averaged 1.8 MBOE/d in the fourth quarter of 2011, which represents more than a 100% increase from 0.9 MBOE/d in the third quarter of 2011.

Redtail Prospect. As of December 31, 2011, we had approximately 105,600 gross (73,600 net) acres in our Redtail prospect in the Weld County, Colorado portion of the Denver Julesburg Basin. In late 2010, we initiated a seven-well exploratory drilling program (five horizontal and two vertical monitor wells) in the Niobrara formation. Based on the results of our exploratory drilling program and recently acquired 3-D seismic data, we plan to drill eight additional wells and continue to operate one drilling rig on this prospect in 2012.

Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of December 31, 2011, the Permian Basin region contributed 128.8 MMBOE (95% oil) of estimated proved reserves to our portfolio of operations, which represented 37% of our total estimated proved reserves and contributed 13.1 MBOE/d of average daily production in December 2011.

North Ward Estes Field. The North Ward Estes field includes six base leases with 100% working interests in approximately 58,000 gross and net acres in Ward and Winkler counties, Texas. Whiting recently began drilling operations at a pilot project in our North Ward Estes field to test a Residual Oil Zone (“ROZ”). Current EOR production 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. We plan to initiate CO2 injection into the deeper ROZ during the first quarter of 2012. In the North Ward Estes field, the estimated proved reserves as of December 31, 2011 were 44% PDP, 15% PDNP and 41% PUD.

The North Ward Estes field is responding positively to our water and CO2 floods, which we initiated in May 2007. Production from the field has increased 4% from 8.4 MBOE/d in the third quarter of 2011 to 8.8 MBOE/d in the fourth quarter of 2011. As of February 1, 2012, we were injecting approximately 300 MMcf/d of CO2 in this field, over half of which is recycled. In this field, we are developing new and reactivated wells for water and CO2 injection and production purposes. Additionally, we plan to install oil, gas and water processing facilities in eight phases. The first three phases are essentially complete and are currently undergoing water and CO2 injection. The field and injection infrastructure of Phase IV is complete and injection has been initiated on about half of the project.

In order to fully develop the proved undeveloped reserves at North Ward Estes within our currently planned timeframe, we will need to utilize significant quantities of purchased CO2. As of December 31, 2011, we currently have under contract 100% of the future CO2 volumes that we believe are necessary to develop the North Ward Estes proved undeveloped reserves. We are currently in negotiations and planning for future sources capable of generating sufficient CO2 quantities to carry out the development of all probable and possible reserves at North Ward Estes. We are therefore reasonably certain that we will be able to successfully obtain all the necessary CO2 quantities required to develop the North Ward Estes proved reserves within our planned timeframe. However, we cannot provide absolute assurance with respect to the timing or actual quantities of CO2 that will be obtainable for the development of oil and gas reserves at North Ward Estes.

Big Tex Prospect. As of December 31, 2011, we had accumulated approximately 120,700 gross (89,800 net) acres in 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. During 2012, we plan to drill 13 wells in the Big Tex prospect, the majority of which are expected to be horizontal Bone Spring wells. This includes a four-well program to test the Wolfcamp horizon with two vertical wells on the western side of our acreage and two horizontal wells on the northern portion of the acreage. We expect to continue to operate two rigs on the prospect in 2012.

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Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. As of December 31, 2011, the Mid-Continent region contributed 41.2 MMBOE (92% oil) of proved reserves to our portfolio of operations, which represented 12% of our total estimated proved reserves and contributed 8.3 MBOE/d of average daily production in December 2011. The majority of the proved value within our Mid-Continent operations is related to properties in the Postle field.

Postle Field. The Postle field, located in Texas County, Oklahoma, includes five producing units and one producing lease covering a total of approximately 25,600 gross (24,200 net) acres. Four of the units are currently active CO2 enhanced recovery projects. In the fourth quarter of 2011, production from the field averaged 8.1 MBOE/d, which is relatively constant as compared to 8.0 MBOE/d in the third quarter of 2011. As of February 1, 2012, we were injecting approximately 120 MMcf/d of CO2 in this field, over half of which is recycled gas. We manage our CO2 flood at Postle on a pattern-by-pattern basis in order to optimize utilization of CO2, production and ultimate recovery. A pattern typically consists of a producing well surrounded by four water/CO2 injectors. As a pattern matures, increasing volumes of water are alternated with CO2 injection to control gas breakthrough and sweep efficiency. This process, referred to as “WAG” (Water Alternating Gas), typically results in the highest possible oil recovery. In the Postle field, the estimated proved reserves as of December 31, 2011 were 90% PDP, 4% PDNP and 6% PUD.

We are the sole owner of the Dry Trails gas plant located in the Postle field. This gas processing plant utilizes a membrane technology to separate CO2 gas from the produced wellhead mixture of hydrocarbon and CO2 gas so that the CO2 gas can be re-injected into the producing formation.

In addition to the producing assets and processing plant, we have a 60% interest in the 120-mile Transpetco operated CO2 transportation pipeline, thereby assuring the delivery of CO2 to the Postle field at a fair tariff. We have a long-term CO2 purchase agreement to provide the necessary CO2 to carry out the flood over the life of the field.

Michigan Region

As of December 31, 2011, our estimated proved reserves in the Michigan region were 10.3 MMBOE (33% oil), which represents 3% of our total estimated proved reserves, and our December 2011 daily production averaged 2.6 MBOE/d. Production in Michigan can be divided into two groups. The majority of the reserves are in non-operated Antrim Shale wells located in the northern part of the state. The remainder of the Michigan reserves are typified by more conventional oil and gas production located in the central and southern parts of the state. 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.

Gulf Coast Region

Our Gulf Coast operations include assets located in Texas, Louisiana and Mississippi. As of December 31, 2011, the Gulf Coast region contributed 5.7 MMBOE (32% oil) of proved reserves to our portfolio of operations, which represented 2% of our total estimated proved reserves and contributed 1.8 MBOE/d of average daily production in December 2011.

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Reserves

As of December 31, 2011, 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, 2011 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, 2011) is as follows:

Summary of Oil and Gas Reserves as of Fiscal-Year End Based on Average Fiscal-Year Prices

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Proved reserves			
Developed	203,084	211,297	238,300
Undeveloped	94,669	73,678	106,949
Total proved—December 31, 2011	297,753	284,975	345,249
Probable reserves			
Developed	1,112	8,337	2,501
Undeveloped	69,722	202,537	103,478
Total probable—December 31, 2011	70,834	210,874	105,979
Possible reserves			
Developed	905	1,891	1,220
Undeveloped	163,148	185,321	194,035
Total possible—December 31, 2011	164,053	187,212	195,255

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 2011, total extensions and discoveries of 48.6 MMBOE were primarily attributable to successful drilling in the Sanish field and Pronghorn area of our Lewis & Clark prospect. These new producing wells and related proved undeveloped locations added during the year increased our proved reserves in the Sanish and Pronghorn areas.

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 our 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 liquids component of the net 14.3 MMBOE revision consisted of a 15.7 MMBOE increase that was primarily related to our Postle and North Ward Estes fields where the performance of our CO_2 injection enhanced oil recovery ("EOR") projects supported an increase in the proved reserve assignments. 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 production performance of two recently completed wells.

Proved undeveloped reserves. From December 31, 2010 to December 31, 2011, our proved undeveloped reserves ("PUDs") increased 19% or 17.2 MMBOE. This increase in proved undeveloped reserves was primarily attributable to additional PUD locations added as a result of successful drilling on recently acquired North Dakota acreage and additional PUD reserves being assigned to our North Ward Estes EOR project. There were 8.2 MMBOE of PUDs that became proved developed reserves during the year as a result of 34 proved undeveloped well locations that were drilled and placed on production in 2011. We incurred $113.9 million in capital expenditures, or $13.82 per BOE, to drill and bring on-line these 34 PUD locations. In addition, there were approximately 4.6 MMBOE of PUDs that became proved developed reserves in 2011 at our CO2 EOR projects in the Postle and North Ward Estes fields. These PUDs were converted to proved developed at a cost of approximately $23.91 per BOE. Combining the PUD drilling conversions with the PUD enhanced oil recovery conversions, the Company converted 12.8 MMBOE of PUDs to proved developed reserves during 2011 at a cost of $17.45 per BOE.

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Based on our 2011 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 enhanced recovery 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 repressure the reservoir in advance of the CO2 injection, (ii) the volume of purchased and recycled CO2 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 CO2 enhanced recovery project. Our staged development plan is designed to expand the project as quickly and efficiently as possible to fully develop the field.

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, even if the interpreted reservoir continuity of structure or productivity does not meet the reasonable certainty criterion. Probable reserves may be assigned to areas that are structurally higher than the proved area if these areas are in communication with the proved reservoir. Probable reserves estimates also include potential incremental quantities associated with a greater percentage recovery of the hydrocarbons in place than assumed for proved reserves.

Increases in probable reserves during 2011 were primarily attributable to (i) 65 new probable undeveloped well locations, which were added in 2011 as a result of our drilling activity on recently acquired acreage in North Dakota and (ii) reserve volumes at North Ward Estes moving from the possible reserve category to the probable reserve category as the continued performance of the EOR projects supports the upgrade in classification.

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.

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Possible reserves decreased during 2011 primarily due to (i) reserve volumes at North Ward Estes moving from the possible reserve category to the probable reserve category as the continued performance of the EOR projects supports the upgrade in classification, and (ii) the reduction in possible reserves assigned to the Sanish field. These reserve volumes, which were based on lower production declines and shallower terminal decline rates have been moved to the proved developed producing reserve assignments or deleted depending on individual well performance.

At December 31, 2011, our probable reserves were estimated to be 105.9 MMBOE and our possible reserves were estimated to be 195.3 MMBOE, for a total of 301.2 MMBOE. The EOR project at our North Ward Estes field represented 115.5 MMBOE, or 38%, of our total 301.2 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 CO2. We are currently in negotiations and planning for future sources capable of generating sufficient CO2 quantities to carry out the development of all probable and possible reserves at North Ward Estes. However, the availability of future CO2 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 CO2 that will be obtainable for the development such reserves.

Preparation of reserves estimates. The Company maintains 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 the Company’s 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 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. The Company’s current ownership in mineral interests and well production data are also subject to the aforementioned internal controls over financial reporting, and they are incorporated in 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, Whiting’s independent engineering firm Cawley, Gillespie & Associates, Inc. (“CG&A”) meets with Whiting’s technical personnel in the Company’s 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 the Company’s 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 38 years of experience, the majority of which has involved reservoir engineering and reserve estimation, holds a Bachelor’s degree in petroleum engineering from the University of Wyoming, holds an MBA from the University of Denver and is a registered Professional Engineer. He has also served on the national Board of Directors of the Society of Petroleum Evaluation Engineers.

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Acreage

The following table summarizes gross and net developed and undeveloped acreage by state at December 31, 2011. 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	25,669	3,727	-	-	25,669	3,727
Colorado	48,658	26,325	135,691	83,798	184,349	110,123
Louisiana	40,064	7,480	3,750	1,875	43,814	9,355
Michigan	142,445	64,102	17,666	12,643	160,111	76,745
Montana	41,361	14,211	203,497	152,159	244,858	166,370
North Dakota	393,147	210,122	472,472	305,108	865,619	515,230
Oklahoma	88,732	57,849	772	471	89,504	58,320
Texas	256,390	143,522	151,660	112,564	408,050	256,086
Utah	26,586	14,844	360,469	185,028	387,055	199,872
Wyoming	96,912	56,269	83,299	50,457	180,211	106,726
Other(1)	17,135	9,073	2,784	1,607	19,919	10,680
Total	1,177,099	607,524	1,432,060	905,710	2,609,159	1,513,234

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

(2) Out of a total of approximately 1,432,060 gross (905,710 net) undeveloped acres as of December 31, 2011, the portion of our net undeveloped acres that is subject to expiration over the next three years, if not successfully developed or renewed, is less than 1% in 2012, approximately 23% in 2013 and 15% in 2014.

Production History

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

	Year Ended December 31,		
	2011	2010	2009
Oil production (MMBbls)	20.4	19.0	15.4
Natural gas production (Bcf)	26.4	27.4	29.3
Total production (MMBOE)	24.8	23.6	20.3
Daily production (MBOE/d)	67.9	64.6	55.5
North Ward Estes field production (1)			
Oil production (MMBbls)	3.0	2.7	2.2
Natural gas production (Bcf)	0.4	0.4	0.6
Total production (MMBOE)	3.0	2.8	2.3
Sanish field production (1)			
Oil production (MMBbls)	7.3	6.8	3.7
Natural gas production (Bcf)	2.2	2.5	1.3
Total production (MMBOE)	7.7	7.2	3.9
Average sales prices:			
Oil (per Bbl)	$ 84.92	$ 70.53	$ 52.51
Natural gas (per Mcf)	$ 4.92	$ 4.86	$ 3.75
Average production costs:			
Production costs (per BOE) (2)	$ 11.77	$ 10.62	$ 11.10

(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, 2011.

(2) Production costs reported above exclude from lease operating expenses ad valorem taxes of $13.9 million ($0.56 per BOE), $17.7 million ($0.75 per BOE) and $12.2 million ($0.61 per BOE) for the years ended December 31, 2011, 2010 and 2009, 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, 2011. 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	2,607	681	420	227	3,027	908
Permian Basin	4,078	1,745	392	129	4,470	1,874
Mid-Continent	573	368	190	73	763	441
Michigan	77	41	1,102	418	1,179	459
Gulf Coast	84	43	410	81	494	124
Total	7,419	2,878	2,514	928	9,933	3,806

(1) 139 wells are multiple completions. These 139 wells contain a total of 342 completions. One or more completions in the same bore hole are counted as one well.

We have an interest in or operate 35 EOR projects, which include both secondary (waterflood) and tertiary (CO2 injection) recovery efforts, and aggregate production from such EOR fields averaged 20.1 MBOE/d during 2011 or 30% of our 2011 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 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
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
2010:						
Development	163	3	166	73.8	0.7	74.5
Exploratory	20	3	23	10.5	3.0	13.5
Total	183	6	189	84.3	3.7	88.0
2009:						
Development	137	4	141	50.2	2.6	52.8
Exploratory	1	3	4	0.9	2.5	3.4
Total	138	7	145	51.1	5.1	56.2

As of December 31, 2011, 27 operated drilling rigs and 67 operated workover rigs were active on our properties. We were also participating in the drilling of two non-operated wells. The breakdown of our operated rigs is as follows:

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Region	Drilling	Workover
Rocky Mountain	21	23
Permian	4	7
Mid-Continent/Michigan	-	1
North Ward Estes	1	30
Postle	1	6
Total	27	67

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 Item 1. "Business – Regulation – Environmental Regulations – Hydraulic Fracturing" of this Annual Report on Form 10-K, the EPA has attempted to begin to regulate 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 North Dakota, Colorado, Michigan, Montana and Texas, and we plan on continuing to utilize this completion methodology.

Proved undeveloped reserves associated with hydraulic fracture treatments consist of substantially all of our proved undeveloped reserves, or 106.9 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. Other than this incident, 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 requirements;
- we train all company and contract personnel 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.

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.

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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. As of December 31, 2011, we had delivery commitments of 5.7 Bcf (or 22% of total 2011 natural gas production), 4.4 Bcf (17%) and 4.0 Bcf (15%) for the years ended December 31, 2012, 2013 and 2014, respectively. These contracts relate to production at our Boies Ranch field in Rio Blanco County, Colorado, our Antrim Shale wells in Michigan and our Flat Rock field in Uintah County, Utah. We believe our production and reserves are adequate to meet these delivery commitments. See "Quantitative and Qualitative Disclosure about Market Risk" in Item 7A of this Annual Report on Form 10-K for more information about these contracts.

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.

Whiting received a complaint, dated September 28, 2011, in an administrative action by the United States Environmental Protection Agency (the "EPA") alleging that Whiting violated the Safe Drinking Water Act by reporting inaccurate wellhead injection pressure data to the EPA for one water injection well in North Dakota and seeking a civil penalty of $151,250. Whiting and the EPA entered into a consent agreement in November 2011, pursuant to which Whiting paid a civil penalty of $120,000 in full settlement of the matter.

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 15, 2012, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	65	Chairman and Chief Executive Officer
James T. Brown	59	President and Chief Operating Officer
Mark R. Williams	55	Senior Vice President, Exploration and Development
Bruce R. DeBoer	59	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	41	Vice President, Human Resources
J. Douglas Lang	62	Vice President, Reservoir Engineering and Acquisitions
Rick A. Ross	53	Vice President, Operations
David M. Seery	57	Vice President, Land
Michael J. Stevens	46	Vice President and Chief Financial Officer
Brent P. Jensen	42	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 40 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 37 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 31 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 32 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 15 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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J. Douglas Lang joined us in December 1999 as Senior Acquisition Engineer and became Manager of Acquisitions and Reservoir Engineering in January 2004 and Vice President, Reservoir Engineering and Acquisitions in October 2004. His 38 years of acquisition and reservoir engineering experience has included staff and managerial positions with Amoco, Petro-Lewis, General Atlantic Resources, UMC Petroleum and Ocean Energy. Mr. Lang holds a Bachelor's degree in petroleum engineering from the University of Wyoming and an MBA from the University of Denver. He is a registered Professional Engineer and has served on the national Board of Directors of the Society of Petroleum Evaluation 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 29 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 and is currently 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 31 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.

Michael J. Stevens joined us in May 2001 as Controller, and became Treasurer in January 2002 and became Vice President and Chief Financial Officer in March 2005. His 25 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 18 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 (as adjusted for the two-for-one stock split as noted below) for the periods presented.

	High	Low
Fiscal Year Ended December 31, 2011		
Fourth Quarter (Ended December 31, 2011)	$ 52.38	$ 28.87
Third Quarter (Ended September 30, 2011)	$ 63.31	$ 34.65
Second Quarter (Ended June 30, 2011)	$ 75.40	$ 52.08
First Quarter (Ended March 31, 2011)	$ 75.91	$ 55.26
Fiscal Year Ended December 31, 2010		
Fourth Quarter (Ended December 31, 2010)	$ 59.40	$ 47.95
Third Quarter (Ended September 30, 2010)	$ 49.14	$ 36.82
Second Quarter (Ended June 30, 2010)	$ 46.61	$ 35.61
First Quarter (Ended March 31, 2010)	$ 40.88	$ 31.33

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. 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. All common share and per share amounts in this Annual Report on Form 10-K for periods prior to February 2011 have been retroactively adjusted to reflect the stock split.

On February 15, 2012, there were 569 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, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, our credit agreement restricts our ability to make any dividends or distributions on our common stock. Additionally, the indentures governing our senior subordinated notes contain restrictive covenants that may limit our ability to pay cash dividends on our common stock and our 6.25% convertible perpetual preferred 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, 2006 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 US 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, 2006 in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones US Oil Companies, Secondary Index.

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	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10	12/31/11
Whiting Petroleum Corporation	$ 100	$ 124	$ 72	$ 153	$ 251	$ 200
Standard & Poor’s Composite 500 Index	100	104	64	79	89	89
Dow Jones US Oil Companies, Secondary Index	100	143	85	118	136	130

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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, 2011, 2010 and 2009 and the consolidated balance sheet information at December 31, 2011 and 2010 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, 2008 and 2007 and the consolidated balance sheet information at December 31, 2009, 2008 and 2007 are derived from audited financial statements that are not included in this report. Our historical results include the results from our recent acquisitions beginning on the following dates: proved properties in Colorado, September 1, 2010; Additional interests in North Ward Estes, November 1, 2009 and October 1, 2009; and Flat Rock natural gas field, May 30, 2008.

	Year Ended December 31,				
	2011	2010	2009	2008	2007
	(dollars in millions, except per share data)				
Consolidated Statements of Income Information:					
Revenues and other income:					
Oil and natural gas sales	$ 1,860.1	$ 1,475.3	$ 917.5	$ 1,316.5	$ 809.0
Gain (loss) on hedging activities	8.8	23.2	38.8	(107.6)	(21.2)
Amortization of deferred gain on sale	13.9	15.6	16.6	12.1	—
Gain on sale of properties	16.3	1.4	5.9	—	29.7
Interest income and other	0.5	0.6	0.6	1.1	1.2
Total revenues and other income	1,899.6	1,516.1	979.4	1,222.1	818.7
Costs and expenses:					
Lease operating	305.5	268.3	237.3	241.2	208.9
Production taxes	139.2	103.9	64.7	87.5	52.4
Depreciation, depletion and amortization	468.2	393.9	394.8	277.5	192.8
Exploration and impairment	84.6	59.4	73.0	55.3	37.3
General and administrative	85.0	64.7	42.3	61.7	39.0
Interest expense	62.5	59.1	64.6	65.1	72.5
Loss on early extinguishment of debt	—	6.2	—	—	—
Change in Production Participation Plan liability	(0.9)	12.1	3.3	32.1	8.6
Commodity derivative (gain) loss, net	(24.8)	7.1	262.2	(7.1)	—
Total costs and expenses	1,119.3	974.7	1,142.2	813.3	611.5
Income (loss) before income taxes	780.3	541.4	(162.8)	408.8	207.2
Income tax expense (benefit)	288.7	204.8	(55.9)	156.7	76.6
Net income (loss)	491.6	336.7	(106.9)	252.1	130.6
Net loss attributable to noncontrolling interest	0.1	-	-	-	-

Net income (loss) available to shareholders	491.7	336.7	(106.9)	252.1	130.6
Preferred stock dividends	(1.1)	(64.0)	(10.3)	—	—
Net income (loss) available to common shareholders	$ 490.6	$ 272.7	$ (117.2)	$ 252.1	$ 130.6
Earnings (loss) per common share, basic(1)	$ 4.18	$ 2.57	$ (1.18)	$ 2.98	$ 1.65
Earnings (loss) per common share, diluted(1)	$ 4.14	$ 2.55	$ (1.18)	$ 2.97	$ 1.65
Other Financial Information:					
Net cash provided by operating activities	$ 1,192.1	$ 997.3	$ 453.8	$ 766.5	$ 394.0
Net cash used in investing activities	$ (1,760.0)	$ (914.6)	$ (523.5)	$ (1,138.5)	$ (467.0)
Net cash provided by (used in) financing activities	$ 564.8	$ (75.7)	$ 72.1	$ 366.8	$ 77.3
Capital expenditures	$ 1,804.3	$ 923.8	$ 585.8	$ 1,330.9	$ 519.6
Consolidated Balance Sheet Information:					
Total assets	$ 6,045.6	$ 4,648.8	$ 4,029.5	$ 4,029.1	$ 2,952.0
Long-term debt	$ 1,380.0	$ 800.0	$ 779.6	$ 1,239.8	$ 868.2
Total equity	$ 3,029.1	$ 2,531.3	$ 2,270.1	$ 1,808.8	$ 1,490.8

(1) 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.

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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 acquisition, development, exploitation, production and exploration activities primarily in the Rocky Mountains, Permian Basin, Mid-Continent, Michigan and Gulf Coast 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 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;
- maintaining a balanced portfolio of lower risk, long-lived oil and gas properties that provide stable cash flows;
- seeking property acquisitions that complement our core areas; and
- allocating a portion of our capital budget to leasing and exploring prospect areas.

We have historically acquired operated and non-operated properties that exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation 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 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.

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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 2010:

	2010				2011			
	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude Oil	$ 78.79	$ 77.99	$ 76.21	$ 85.18	$ 94.25	$ 102.55	$ 89.81	$ 94.02
Natural Gas	$ 5.30	$ 4.09	$ 4.39	$ 3.81	$ 4.10	$ 4.32	$ 4.20	$ 3.54

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 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 non-cash, 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, 2010 to December 31, 2011 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.

2011 Highlights and Future Considerations

Operational Highlights.

Lewis & Clark/Pronghorn. Our Lewis & Clark/Pronghorn prospects 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. Net production in the Lewis & Clark/Pronghorn prospects averaged 5.9 MBOE/d in the fourth quarter of 2011, representing a 48% increase from 4.0 MBOE/d in the third quarter of 2011. We currently have six drilling rigs operating in the Pronghorn prospect and two drilling rigs operating in the Lewis & Clark prospect.

In December 2011, we completed and commissioned the gas processing plant located south of Belfield, North Dakota, which will have a processing capacity of 30 MMcf/d and which will primarily process production from the Pronghorn area. In January 2012, we completed construction on an oil terminal and a seven-mile oil transmission line to allow for the delivery of oil production from the Pronghorn into the Bridger Four Bears oil transmission system. The completion of this terminal will reduce our transportation costs per barrel.

Hidden Bench/Tarpon. Our Hidden Bench and Tarpon prospects in McKenzie County, North Dakota target the Bakken and Three Forks formations. Net production at Hidden Bench averaged 1.8 MBOE/d in the fourth quarter of 2011, which represents more than a 100% increase from 0.9 MBOE/d in the third quarter of 2011.

Sanish. Our Sanish field in Mountrail County, North Dakota targets the Bakken and Three Forks formations. Net production in the Sanish field averaged 22.9 MBOE/d for the fourth quarter of 2011 but ended the quarter averaging 25.7 MBOE/d in December 2011. This compares to production of 24.1 MBOE/d from the Sanish field for the third quarter of 2011. During the fourth quarter of 2011, we completed 19 operated wells, bringing the total number of producing wells in the field to 218. As of February 1, 2012, we had 33 service units active in the Williston Basin. These service units have reduced the number of shut-in wells in Sanish field from 66 as of October 22, 2011 to 31 as of February 1, 2012. We expect to continue to reduce the number of shut-in wells awaiting service work in this field during the first quarter of 2012.

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North Ward Estes. 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 reserve additions and production increases, 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. In the fourth quarter of 2011, production from North Ward Estes averaged 8.8 MBOE/d representing a 4% increase from 8.4 MBOE/d in the third quarter 2011. During June 2011, we experienced under-deliveries of CO2 contract quantities from our North Ward Estes CO2 supplier. However, during July and August 2011 our daily CO2 deliveries increased, and since September 1, 2011, we have been receiving our full contract quantities of 134 MMcf/d of CO2. As of February 1, 2012, we were injecting approximately 300 MMcf/d of CO2 into the field, over half of which is recycled.

Postle. The Postle field is located in Texas County, Oklahoma and produces from the Morrow sandstone. Postle averaged 8.1 MBOE/d in the fourth quarter of 2011, which represents a 1% increase from 8.0 MBOE/d in the third quarter of 2011. As of February 1, 2012, we were injecting approximately 120 MMcf/d of CO2 into the field, over half of which is recycled.

Big Tex. Our Big Tex prospect in Pecos, Reeves and Ward counties, Texas targets the Brushy Canyon, Bone Spring and Wolfcamp horizons. During 2012, we plan to drill 13 wells in the Big Tex prospect, the majority of which are expected to be horizontal Bone Spring wells. This includes a four-well program to test the Wolfcamp horizon with two vertical wells on the western side of our acreage and two horizontal wells on the northern portion of the acreage. We expect to continue to operate two rigs on the prospect in 2012.

Redtail. Our Redtail prospect in Weld County, Colorado targets the Niobrara formation. In late 2010, we initiated a seven-well exploratory drilling program (five horizontal and two vertical monitor wells) in the Niobrara formation. Based on the results of our exploratory drilling program and recently acquired 3-D seismic data, we plan to drill eight additional wells and continue to operate one drilling rig on this prospect in 2012.

Financing Highlights. 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. 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. All common share and per share amounts in this Annual Report on Form 10-K for periods prior to February 2011 have been retroactively adjusted to reflect the stock split.

In May 2011, our 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.

In October 2011, we entered into an amendment to our existing credit agreement that increased our borrowing base under the facility from $1.1 billion to $1.5 billion. All other terms of the credit agreement remain unchanged.

In December 2011, we filed a registration statement, and in January we filed an amendment thereto, relating to a proposed initial public offering of units of beneficial interest in Whiting USA Trust II. We plan to contribute a term net profits interest in certain of our oil and natural gas properties in exchange for trust units, and we will in turn then offer such trust units to the public. These property interests had estimated reserves of up to 18.3 MMBOE, as of a January 1, 2012 effective date, representing up to 5% of our proved reserves as of December 31, 2011, and 7%, or 4.9 MBOE/d, of our December 2011 average daily net production. We intend to use the net proceeds from this offering to repay a portion of the debt outstanding under our credit agreement. The amount of proceeds ultimately received from this offering, and the timing of the completion of this offering, is subject to a variety of factors, including favorable market conditions. We cannot provide any assurance, however, that we will be able to complete this offering or any other form of asset sales.

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2012 Capital Budget and Major Development Areas. Our current 2012 capital budget is $1,600.0 million, which we expect to fund substantially with net cash provided by our operating activities. This represents a 13% decrease from the $1,840.2 million incurred on exploration, development and acreage expenditures during 2011. However, based on this level of capital spending, we are forecasting production growth over our 2011 production level of 24.8 MMBOE. We expect to allocate $1,235.3 million of our 2012 budget to exploration and development activity, $136.2 million for land and $228.5 million for facilities. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would adjust our capital budget accordingly or adjust borrowings outstanding under our credit facility as needed. Our 2012 capital budget currently is allocated among our major development areas as indicated in the chart 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		2012 Planned Capital Expenditures (In millions)
Northern Rockies	$	851.1
CO2 projects (1)		176.7
Permian		60.3
Central Rockies		49.6
Michigan		-
Gulf Coast		-
Non-operated		42.0
Land		136.2
Exploration (2)		55.6
Facilities		228.5
Total	$	1,600.0

(1) 2012 planned capital expenditures at our CO2 projects include $68.5 million for North Ward Estes CO2 purchases and $14.9 million for Postle CO2 purchases.

(2) Comprised primarily of exploration salaries, seismic activities and lease delay rentals.

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Results of Operations

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

	Year Ended December 31,		
	2011	2010	2009
Net production:			
Oil (MMBbls)	20.4	19.0	15.4
Natural gas (Bcf)	26.4	27.4	29.3
Total production (MMBOE)	24.8	23.6	20.3
Net sales (in millions):			
Oil (1)	$ 1,730.1	$ 1,342.2	$ 807.6
Natural gas (1)	130.0	133.1	109.9
Total oil and natural gas sales	$ 1,860.1	$ 1,475.3	$ 917.5
Average sales prices:			
Oil (per Bbl)	$ 84.92	$ 70.53	$ 52.51
Effect of oil hedges on average price (per Bbl)	(1.50)	(1.34)	(0.43)
Oil net of hedging (per Bbl)	$ 83.42	$ 69.19	$ 52.08
Average NYMEX price (per Bbl)	$ 95.14	$ 79.55	$ 61.93
Natural gas (per Mcf)	$ 4.92	$ 4.86	$ 3.75
Effect of natural gas hedges on average price (per Mcf)	0.04	0.04	0.05
Natural gas net of hedging (per Mcf)	$ 4.96	$ 4.90	$ 3.80
Average NYMEX price (per Mcf)	$ 4.04	$ 4.39	$ 3.99
Cost and expenses (per BOE):			
Lease operating expenses	$ 12.33	$ 11.37	$ 11.71
Production taxes	$ 5.62	$ 4.40	$ 3.19
Depreciation, depletion and amortization expense	$ 18.89	$ 16.69	$ 19.48
General and administrative expenses	$ 3.43	$ 2.74	$ 2.09

(1) Before consideration of hedging transactions.

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

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $384.8 million to $1,860.1 million in 2011 compared to 2010. Sales are a function of oil and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 7% between periods, while our natural gas sales volumes decreased 3%. The oil volume increase resulted primarily from drilling success at our Lewis & Clark field and our Hidden Bench prospect, as well as increased production attributable to our CO2 project at North Ward Estes. Oil production from our Lewis & Clark field increased 1,045 MBbl, while oil production from our Hidden Bench prospect increased 240 MBbl, and oil production at our North Ward Estes field increased 300 MBbl over the same period in 2010. These production increases were partially offset by a decrease in oil production volumes of 400 MBbl at our Postle field primarily due to normal oil and gas production decline at this field. Gas production volumes decreased between periods primarily due to normal field production decline across many of our areas. Additionally, gas production at our Sanish and Parshall fields decreased 450 MMcf due to a large number of shut-in wells in this area during the second half of 2011. These gas volume decreases were largely offset by increased gas production of 1,755 MMcf at our Flat Rock field due to new wells drilled and completed in the area during the last twelve months.

Also contributing to the increase in oil and gas sales revenue in 2011 was an increase in the average sales price realized for oil. Our average price for oil before the effects of hedging increased 20% between periods, which was mainly due to higher average NYMEX prices during 2011, and our average price for natural gas before the effects of hedging increased 1%.

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Gain (Loss) on Hedging Activities. Our gain on hedging activities decreased $14.4 million in 2011 as compared to 2010, and it consisted of the following (in thousands):

	Year Ended December 31,	
	2011	2010
Gains reclassified from AOCI on de-designated hedges	$ 8,758	$ 23,198

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 (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 as gain on hedging activities.

See Item 7A, "Quantitative and Qualitative Disclosures about Market Risk," for a list of our outstanding oil and natural gas derivatives as of January 31, 2012.

Lease Operating Expenses. Our lease operating expenses ("LOE") during 2011 were $305.5 million, a $37.1 million increase over the same period in 2010. This rise in LOE in 2011 was related to a higher level of workover activity, as well as a $24.5 million increase in the cost of oil field goods and services associated with net wells we added during the last twelve months. Workovers increased to $79.2 million in 2011, as compared to $66.6 million in 2010, primarily due to a higher number of well workovers being conducted on our two main CO2 projects.

Our lease operating expenses on a BOE basis also increased to $12.33 during 2011 from $11.37 during 2010. This increase on a BOE basis was mainly due to the higher amount of workover activity in 2011, as discussed above.

Production Taxes. Our production taxes during 2011 were $139.2 million, a $35.3 million increase over the same period in 2010, which increase was primarily due to higher oil and natural gas sales between periods. However, our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging, and this percentage on a company-wide basis was 7.5% and 7.0% for 2011 and 2010, respectively. In addition, we take advantage of credits and exemptions allowed in our various taxing jurisdictions.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $74.3 million in 2011 as compared to 2010. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2011	2010
Depletion	$ 457,499	$ 384,383
Depreciation	2,688	2,291
Accretion of asset retirement obligations	8,016	7,223
Total	$ 468,203	$ 393,897

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DD&A increased in 2011 primarily due to $73.1 million in higher depletion expense between periods. This increase was the result of $51.2 million in higher depletion due to an increase in our depletion rate between periods and $21.9 million in higher depletion due to a rise in overall production volumes during 2011. On a BOE basis, our DD&A rate of $18.89 for 2011 was 13% higher than the rate of $16.69 for 2010. The higher DD&A rate was mainly due to $1,549.3 million in drilling and development expenditures during the past twelve months, which was partially offset by reserve additions during this same time period.

Exploration and Impairment Costs. Our exploration and impairment costs increased $25.3 million in 2011 as compared to 2010. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31, 2011	Year Ended December 31, 2010
Exploration	$ 45,861	$ 32,846
Impairment	38,783	26,525
Total	$ 84,644	$ 59,371

Exploration costs increased $13.0 million during 2011 as compared to 2010 primarily due to an increase in geology related general and administrative expenses, an increase in geological and geophysical (“G&G”) activity and higher exploratory dry hole costs. Geology related general and administrative expenses increased $5.9 million between periods. G&G costs, such as seismic studies, amounted to $19.0 million during 2011 as compared to $14.3 million during 2010. During 2011, we drilled three exploratory dry holes in the Rocky Mountains, Permian Basin and Gulf Coast regions totaling $4.9 million, while we drilled three exploratory dry holes in the Gulf Coast region totaling $3.8 million during 2010. Impairment expense in 2011 and 2010 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. A higher amount of undeveloped leasehold costs were amortized to impairment on a group basis for 2011 as compared to 2010. Also included in impairment expense for 2011 is $3.2 million in non-cash impairment charges for the partial write-down of mainly natural gas proved properties whose net book values exceeded their undiscounted future cash flows, whereas 2010 impairment expense included a $5.8 million impairment write-down of the remaining undeveloped leasehold costs related to the central Utah Hingeline play.

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, 2011	Year Ended December 31, 2010
General and administrative expenses	$ 153,341	$ 118,606
Reimbursements and allocations	(68,356)	(53,912)
General and administrative expense, net	$ 84,985	$ 64,694

General and administrative expense before reimbursements and allocations increased $34.7 million to $153.3 million during 2011 as compared to 2010 primarily due to higher employee compensation and an increase in accrued Production Participation Plan (the “Plan”) distributions. Employee compensation increased $25.2 million in 2011 due to personnel hired during the past twelve months, general pay increases and higher stock compensation between periods. Accrued distributions under the Plan increased $6.9 million when comparing 2011 to 2010. The increase in reimbursements and allocations in 2010 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales increased from 4% for 2010 to 5% for 2011.

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

	Year Ended December 31, 2011	2010
Senior Subordinated Notes	$ 40,250	$ 42,034
Credit agreement	17,049	9,225
Amortization of debt issue costs and debt discount	8,682	10,592
Other	109	147
Capitalized interest	(3,574)	(2,920)
Total	$ 62,516	$ 59,078

The increase in interest expense of $3.4 million between periods was mainly due to higher interest on our credit agreement of $7.8 million due to a greater amount of borrowings outstanding under our credit agreement during 2011. This increase was partially offset by lower amortization of debt issuance costs and debt discounts of $1.9 million and lower interest of $1.8 million on our Senior Subordinated Notes. These decreases resulted from redeeming $150.0 million of 7.25% notes and $220.0 million of 7.25% notes in early September 2010. Also in September 2010, we subsequently issued $350.0 million of 6.5% notes due 2018. Our weighted average debt outstanding during 2011 was $1,151.5 million versus $739.9 million for 2010. Our weighted average effective cash interest rate was 5.0% during 2011 compared to 6.9% during 2010.

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 is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty. However, only cash settlement gains and losses on derivative contracts that are not embedded derivatives are recorded immediately to earnings as commodity derivative (gain) loss, net. The components of commodity derivative (gain) loss, net were as follows (in thousands):

	Year Ended December 31, 2011	2010
Change in unrealized (gains) losses on derivative contracts	$ (54,336)	$ (17,537)
Realized cash settlement losses	29,479	24,599
Total	$ (24,857)	$ 7,062

With respect to our open derivative contracts at December 31, 2011 and 2010, the futures curve of forecasted commodity prices (“forward price curve”) for crude oil generally exceeded the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value liability position at the end of each respective period. The change in unrealized (gains) losses on derivative contracts in 2011 resulted in a $54.3 million gain in such net liability position due to the significant downward shift in the forward price curve for NYMEX crude oil from January 1 to December 31, 2011. The change in unrealized (gains) losses on derivative contracts in 2010 resulted in a $17.5 million gain due to a less significant downward shift in the same forward price curve from January 1 to December 31, 2010.

Income Tax Expense (Benefit). Income tax expense totaled $288.7 million for 2011 as compared to $204.8 million of income tax for 2010, an increase of $83.9 million related to the higher amount of pre-tax income between periods. However, our effective income tax rate decreased from 37.8% for 2010 to 37.0% for 2011. This change in our effective income tax rate between periods was primarily attributable to recent North Dakota corporate tax legislation, which created a one-time benefit in 2011. Our effective tax rates for 2011 and 2010 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences.

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Year Ended December 31, 2010 Compared to Year Ended December 31, 2009

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $557.7 million to $1,475.3 million in 2010 compared to 2009. Sales are a function of oil and gas volumes sold and average commodity prices realized. Our oil sales volumes increased 24% between periods, while our natural gas sales volumes decreased 7%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area in addition to increased production attributable to our two large CO2 projects, Postle and North Ward Estes. Oil production from the Bakken in 2010 increased 3,035 MBbl compared to 2009, while North Ward Estes oil production increased 470 MBbl and Postle oil production increased 375 MBbl over the same period in 2009. The gas volume decrease between periods was primarily the result of normal field production decline, which led to gas production decreases of 1,395 MMcf and 1,375 MMcf at our Boies Ranch and Canyon areas, respectively, compared to 2009. These production decreases were partially offset by increased gas production of 1,465 MMcf and 765 MMcf at our North Dakota Bakken and Flat Rock areas, respectively.

Increases in average sales prices also contributed to the increase in oil and natural gas sales revenue in 2010. Our average price for oil before the effects of hedging increased 34% between periods, and our average price for natural gas before the effects of hedging increased 30%. In addition to higher average NYMEX pricing during 2010 as compared to 2009, natural gas sales price increases were also due to fixed-price gas contracts entered into at our Flat Rock and Boies Ranch areas that carried a weighted-average price of $5.33 per Mcf during 2010. These contracts were in effect starting in the latter portion of the fourth quarter of 2009. See Item 7A, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding fixed-price natural gas contracts as of January 31, 2012.

Gain (Loss) on Hedging Activities. Our gain on hedging activities decreased $15.6 million in 2010 as compared to 2009, and it consisted of the following (in thousands):

	Year Ended December 31,	
	2010	2009
Gains reclassified from AOCI on de-designated hedges	$ 23,198	$ 25,326
Realized cash settlement gains on crude oil hedges	-	13,450
Total	$ 23,198	$ 38,776

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 AOCI into earnings unrealized gains (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 as gain on hedging activities. Prior to April 1, 2009, however, realized cash settlements gains or losses on hedge-designated crude oil derivatives were also included in gain on hedging activities.

See Item 7A, “Quantitative and Qualitative Disclosures about Market Risk,” for a list of our outstanding oil and natural gas derivatives as of January 31, 2012.

Lease Operating Expenses. Our lease operating expenses (“LOE”) during 2010 were $268.3 million, a $31.1 million increase over the same period in 2009. This rise in LOE in 2010 was related to increases of $6.3 million in transportation charges, $5.5 million in ad valorem taxes and $4.6 million in electricity costs between periods, as well as a higher level of workover activity. The increase in transportation charges was primarily due to higher transportation fees on non-operated properties in the Bakken. Workovers increased to $66.6 million in 2010, as compared to $49.8 million in 2009, and this increase in workover activity primarily related to our two CO2 projects, which involved a higher number of producing wells and service wells than they did in 2009.

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Our lease operating expenses on a BOE basis, however, decreased from $11.71 during 2009 to $11.37 during 2010. This decrease of 3% on a BOE basis was primarily the result of the increase in overall production volumes between periods.

Production Taxes. Our production taxes during 2010 were $103.9 million, a $39.2 million increase over the same period in 2009, which increase was primarily due to higher oil and natural gas sales between periods. Our production taxes are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging, and this percentage on a company-wide basis remained constant at 7.0% for 2010 and 2009. In addition, we take advantage of credits and exemptions allowed in our various taxing jurisdictions.

Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense decreased $0.9 million in 2010 as compared to 2009. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2010	2009
Depletion	$ 384,383	$ 384,519
Depreciation	2,291	3,147
Accretion of asset retirement obligations	7,223	7,126
Total	$ 393,897	$ 394,792

Depletion expense decreased $0.1 million in 2010 as compared to 2009. This decrease was the result of $63.2 million in lower depletion expense due to a decrease in our depletion rate between periods, which was largely offset by $63.1 million of additional depletion expense due to higher overall production volumes during 2010. On a BOE basis, our DD&A rate of $16.69 for 2010 was 14% lower than the rate of $19.48 for 2009. The primary factor causing this lower DD&A rate was a net increase in our proved reserves of 35.9 MMBOE as of December 31, 2009, as well as 40.6 MMBOE of proved developed and 29.8 MMBOE of total proved reserves added during 2010. These factors were partially offset by $790.0 million in drilling and development expenditures during the past twelve months.

Exploration and Impairment Costs. Our exploration and impairment costs decreased $13.6 million in 2010 as compared to 2009. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2010	2009
Exploration	$ 32,846	$ 46,875
Impairment	26,525	26,139
Total	$ 59,371	$ 73,014

Exploration costs decreased $14.0 million during 2010 as compared to 2009 primarily due to lower exploratory dry hole expense and reduced rig termination fees. During 2010, we drilled three exploratory dry holes in the Gulf Coast region totaling $3.8 million, while during the same period in 2009, we drilled three exploratory dry holes in the Rocky Mountains region totaling $18.2 million. No rig termination fees were paid during 2010, while rig termination fees totaled $6.5 million during 2009. These decreases were partially offset by an increase in geological and geophysical ("G&G") costs, which amounted to $14.3 million during 2010 compared to $7.0 million during the same period in 2009. Impairment expense in 2010 and 2009 primarily related to the amortization of leasehold costs associated with individually insignificant unproved properties. A higher amount of undeveloped leasehold costs were amortized to impairment on a group basis in 2010 as compared to 2009. Also included in 2010, was a $5.8 million impairment write-down of the remaining undeveloped leasehold costs related to the central Utah Hingeline play, whereas impairment expense in 2009 included $9.4 million in non-cash impairment charges for the partial write-down of proved properties, that were primarily natural gas properties.

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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, 2010	2009
General and administrative expenses	$ 118,606	$ 92,837
Reimbursements and allocations	(53,912)	(50,480)
General and administrative expense, net	$ 64,694	$ 42,357

General and administrative expense before reimbursements and allocations increased $25.8 million to $118.6 million during 2010 primarily due to an increase in accrued Plan distributions, higher employee compensation and 2010 offering costs related to the 6.25% convertible perpetual preferred stock exchange offer. The largest component of the increase related to $13.2 million in higher accrued distributions under the Plan between periods. Employee compensation increased $10.5 million in 2010 due to higher stock compensation between periods, personnel hired during the past twelve months and general pay increases. In addition, we incurred $2.2 million of offering costs in 2010 related to the 6.25% convertible perpetual preferred stock exchange offer completed in September. The increase in reimbursements and allocations in 2010 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses as a percentage of oil and natural gas sales decreased from 5% for 2009 to 4% for 2010.

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

	Year Ended December 31, 2010	2009
Senior Subordinated Notes	$ 42,034	$ 43,907
Credit agreement	9,225	12,891
Amortization of debt issue costs and debt discount	10,592	11,027
Other	147	189
Capitalized interest	(2,920)	(3,406)
Total	$ 59,078	$ 64,608

The decrease in interest expense of $5.5 million between periods was mainly due to lower borrowings outstanding under our credit agreement during 2010, which reduced the interest on our credit agreement by $3.7 million. In addition, interest on our Senior Subordinated Notes decreased by $1.9 million due to the redemption of $150.0 million of 7.25% notes due 2012 and $220.0 million of 7.25% notes due 2013 in early September 2010, and also in September 2010, we subsequently issued $350.0 million of 6.5% notes due 2018. These decreases in interest were partially offset by lower amounts of capitalized interest between periods. Our weighted average debt outstanding during 2010 was $739.9 million versus $1,008.5 million for 2009. Our weighted average effective cash interest rate was 6.9% during 2010 compared to 5.7% during 2009.

Commodity Derivative (Gain) Loss, Net. During the past three years, we entered into commodity derivative contracts that we did not designate as cash flow hedges. In addition, 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 elected to discontinue hedge accounting prospectively. Accordingly, beginning April 1, 2009 all of our derivative contracts are marked-to-market each quarter with fair value gains and losses recognized immediately in earnings. Cash flow is only impacted to the extent that actual cash settlements under these contracts result in making or receiving a payment from the counterparty, and such cash settlement gains and losses are also recorded immediately to earnings as commodity derivative (gain) loss, net.

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The components of our commodity derivative (gain) loss, net were as follows (in thousands):

	Year Ended December 31,	
	2010	2009
Change in unrealized (gains) losses on derivative contracts	$ (17,537)	$ 220,926
Realized cash settlement losses	24,599	18,634
Loss on hedging ineffectiveness	-	22,655
Total	$ 7,062	$ 262,215

With respect to our open derivative contracts at December 31, 2010 and 2009, the futures curve of forecasted commodity prices ("forward price curve") for crude oil generally exceeded the forward price curves that were in effect when the majority of these contracts were entered into, resulting in a net fair value liability position at the end of each respective period. The change in unrealized (gains) losses on derivative contracts in 2010 resulted in a $17.5 million gain in such net liability position due to the downward shift in the forward price curve for NYMEX crude oil from January 1 to December 31, 2010. The change in unrealized (gains) losses on derivative contracts in 2009, on the other hand, resulted in a $220.9 million loss due to the significant upward shift in the same forward price curve from January 1 to December 31, 2009.

During the first quarter of 2009, we recognized a loss of $22.7 million for the ineffective portion of changes in fair value on our commodity derivatives then designated as cash flow hedges.

Income Tax Expense (Benefit). Income tax expense totaled $204.8 million for 2010 as compared to a $56.0 million income tax benefit for 2009, an increase of $260.7 million related to pre-tax earnings shifting from a net loss of $162.8 million in 2009 to net income of $541.4 million for 2010. Our effective income tax rate increased from 34.4% for 2009 to 37.8% for 2010. This change in our effective income tax rate was primarily due to the change from a net loss in 2009 to net income in 2010. Our effective tax rates for 2010 and 2009 differ from the U.S. statutory income tax rate primarily due to the effects of state income taxes and permanent taxable differences.

Liquidity and Capital Resources

Overview. At December 31, 2011, our debt to total capitalization ratio was 31.4%, we had $15.8 million of cash on hand and $3,020.9 million of equity. At December 31, 2010, our debt to total capitalization ratio was 24.0%, we had $19.0 million of cash on hand and $2,531.3 million of equity. In 2011, we generated $1,192.1 million of cash provided by operating activities, an increase of $194.8 million from 2010. Cash provided by operating activities increased primarily due to higher crude oil production volumes and higher average sales prices for both crude oil and natural gas in 2011. These positive factors were partially offset by lower natural gas production volumes in 2011, as well as increased lease operating expenses, production taxes, G&G costs, and general and administrative expenses during 2011 as compared to 2010. Cash flows from operating activities plus $580.0 million in net borrowings under our credit agreement and $69.3 million of proceeds from the sale of properties were used to finance $1,554.3 million of drilling and development expenditures, $250.0 million of cash acquisition capital expenditures paid in 2011 and the issuance of a $25.0 million note receivable. The following chart details our exploration, development and undeveloped acreage expenditures incurred by region during 2011 (in thousands):

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	Drilling and Development Expenditures(1)	Undeveloped Leasehold Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 1,175,030	$ 167,544	$ 21,750	$ 1,364,324	74 %
Permian Basin	328,534	19,071	19,032	366,637	20 %
Mid-Continent	88,016	-	2,083	90,099	5 %
Gulf Coast	5,171	25	2,882	8,078	-
Michigan	10,634	268	114	11,016	1 %
Total incurred	1,607,385	186,908	45,861	1,840,154	100 %
Increase in accrued capital expenditures	(58,038)	-	-	(58,038)	
Total paid	$ 1,549,347	$ 186,908	$ 45,861	$ 1,782,116	

(1) For purposes of this schedule, exploratory dry hole costs of $4.9 million are excluded from drilling and development expenditures as reported on the statement of cash flows and instead have been included in exploration expenditures above.

We continually evaluate our capital needs and compare them to our capital resources. Our current 2012 capital budget is $1,600.0 million, which we expect to fund substantially with net cash provided by our operating activities. This represents a 13% decrease from the $1,840.2 million incurred on exploration, development and acreage expenditures during 2011. However, based on this level of capital spending, we are forecasting production growth over our 2011 production level of 24.8 MMBOE. We expect to allocate $1,235.3 million of our 2012 budget to exploration and development activity, $136.2 million for undeveloped acreage and $228.5 million for facilities. Although we have only budgeted $136.2 million for undeveloped leaseholds in 2012, 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 $1,600.0 million, 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, 2011 had a borrowing base of $1.5 billion with $718.6 million of available borrowing capacity, which was net of $780.0 million in borrowings and $1.4 million in letters of credit 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 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, 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, 2011, $48.6 million was available for additional letters of credit under the agreement.

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The credit agreement provides for interest only payments until April 2016, when the entire amount borrowed is 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.

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, which include the payment of dividends on our 6.25% convertible perpetual preferred stock, 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 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter 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, 2011.

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 Subordinated Notes. 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.

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, 2011. However, a substantial or extended decline in oil 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 $119.0 million (which amount comprises both the long and short-term portions of this obligation) as of December 31, 2011, since we cannot determine with accuracy the timing or amounts of future payments. The following table summarizes our obligations and commitments as of December 31, 2011 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 (a)	$ 1,380,000	$ -	$ 250,000	$ 780,000	$ 350,000
Cash interest expense on debt (b)	268,858	58,625	101,208	69,212	39,813
Derivative contract liability fair value (c)	121,410	73,647	47,763	-	-
Asset retirement obligations (d)	69,721	7,737	6,696	5,961	49,327
Tax sharing liability (e)	22,687	1,526	21,161	-	-
Purchase obligations (f)	783,201	52,396	142,880	236,392	351,533
Drilling rig contracts (g)	270,949	101,059	152,827	17,063	-
Operating leases (h)	8,161	3,959	3,642	560	-
Total	$ 2,924,987	$ 298,949	$ 726,177	$ 1,109,188	$ 790,673

(a) Long-term debt consists of the 7% Senior Subordinated Notes due 2014, the 6.5% Senior Subordinated Notes due 2018 and the outstanding borrowings under our credit agreement due in 2016, and assumes no principal repayment until the due date of the instruments.

(b) Cash interest expense on the 7% Senior Subordinated Notes due 2014 and the 6.5% Senior Subordinated Notes due 2018 is estimated assuming no principal repayment until the due date of the instruments. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the 2016 instrument due date and is estimated at a fixed interest rate of 2.4%.

(c) The above derivative obligation at December 31, 2011 consists of a $117.1 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. With respect to our open derivative contracts at December 31, 2011 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. The above derivative obligation at December 31, 2011 also consists of a $4.3 million payable to Whiting USA Trust I (the "Trust") for derivative contracts that we have entered into but have in turn conveyed to the Trust. Although these derivatives are in a fair value asset position at quarter end, 75.8% of such derivative assets are due to the Trust under the terms of the conveyance.

(d) 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 facilities.

(e)

Amounts shown represent the present value of estimated payments 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 for the years ending on or prior to December 31, 2013. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years.

(f) We have four take-or-pay purchase agreements, two agreements 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 enhanced recovery projects in our Postle field in Oklahoma and our North Ward Estes field in Texas. The purchase agreements are with three 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 two ship-or-pay agreements with two different parties, one expiring in June 2013 and one expiring in December 2017, whereby we have committed to transport a minimum daily volume of CO2 via certain pipelines or else pay for any deficiencies at a price stipulated in the contract. The CO2 volumes planned for use in the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes specified in 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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(g) We currently have 14 drilling rigs under long-term contract, of which three drilling rigs expire in 2012, two in 2013, six in 2014 and three in 2015. All of these rigs are operating in the Rocky Mountains region. As of December 31, 2011, early termination of the remaining contracts would require termination penalties of $205.8 million, which would be in lieu of paying the remaining drilling commitments of $270.9 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.

(h) We lease 135,026 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, 46,700 square feet of office space in Midland, Texas expiring in 2012 and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016.

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 Adopted and Recently Issued Accounting Pronouncements 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.

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 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, 2011. 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, asset retirement obligations 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 the 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, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation 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 future net undiscounted cash flows to the net book value at the end of each period. If the net capitalized cost exceeds 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 (“AROs”) consist primarily 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 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 ("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 Production Participation 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 Production Participation 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 Production Participation 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, 2011 would have decreased net income before taxes by $13.1 million in 2011.

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, they 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 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), actual results, 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.

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 related to prevailing oil and natural gas prices).

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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 and 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 insignificant.

Accounting for Business Combinations. Our business has grown substantially 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 of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is recognized immediately to earnings as a gain from bargain purchase.

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

Each of the business combinations completed during the 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.

Effects of Inflation and Pricing

During the first quarter of 2010, we began to experience moderate cost increases, as the demand for oil field products and services had begun to rise from 2009 levels. The price increases continued through the remainder of 2010 and 2011. 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 put 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 the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans, depletion expense, impairment assessments of oil and gas properties, and values of properties in purchase and sale transactions. Material changes in prices can impact the value of oil and gas companies and their ability to raise capital, borrow money and retain personnel. While we do not currently expect business costs to materially increase, higher prices for oil and natural gas could result in increases in the costs of materials, services and personnel.

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Forward-Looking Statements

This report contains statements that we believe to be “forward-looking statements” within the meaning of the Private Securities Litigation Reform Act of 1995. 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 “sho 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 or natural gas prices; our level of success in exploitation, exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures, including our ability to obtain CO_2; inaccuracies of our reserve estimates or our assumptions underlying them; revisions to reserve estimates as a result of changes in commodity prices; 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; impacts of the global recession and tight credit markets; 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; 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. The prices we receive for our production depend on numerous factors beyond our control. Based on 2011 production, our income before income taxes for 2011 would have moved up or down $20.4 million for each $1.00 per Bbl change in oil prices and $2.6 million for every $0.10 per Mcf change in natural gas prices.

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. Starting April 1, 2009, we have not applied hedge accounting, and therefore all changes in commodity derivative fair values since that date have been recorded immediately to earnings. Recognition of derivative settlement gains and losses in the consolidated statements of income occurs in the period that hedged production volumes are sold.

Commodity Derivative Contracts—Our outstanding hedges as of January 31, 2012 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	01/2012 to 03/2012	975,000	$66.56/$108.26
Crude Oil	04/2012 to 06/2012	975,000	$66.56/$108.26
Crude Oil	07/2012 to 09/2012	975,000	$66.56/$108.26
Crude Oil	10/2012 to 12/2012	975,000	$66.56/$108.26
Crude Oil	01/2013 to 03/2013	290,000	$47.67/$90.21
Crude Oil	04/2013 to 06/2013	290,000	$47.67/$90.21
Crude Oil	07/2013 to 09/2013	290,000	$47.67/$90.21
Crude Oil	10/2013	290,000	$47.67/$90.21
Crude Oil	11/2013	190,000	$47.22/$85.06

In connection with our conveyance on April 30, 2008 of a term net profits interest to Whiting USA Trust I (the "Trust"), the rights to any future hedge payments we make or receive on certain of our derivative contracts, representing 434 MBbls of crude oil and 1,587 MMcf of natural gas in 2012, have been conveyed to the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the terms of the aforementioned conveyance, we retain 10% of the net proceeds from the underlying properties. Our retention of 10% of these net proceeds combined with our ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, while we retain 24.2%, of future economic results of such hedges. No additional hedges are allowed to be placed on Trust assets.

The table below summarizes all of the costless collars that we entered into and then in turn conveyed, as described in the preceding paragraph, to Whiting USA Trust I (of which we retain 24.2% of the future economic results and third-party public holders of Trust units receive 75.8% of the future economic results):

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Conveyed to Whiting USA Trust I

Commodity	Period	Monthly Volume (Bbl)/(MMBtu)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	01/2012 to 03/2012	37,412	$74.00/$141.27
Crude Oil	04/2012 to 06/2012	36,572	$74.00/$141.73
Crude Oil	07/2012 to 09/2012	35,742	$74.00/$141.70
Crude Oil	10/2012 to 12/2012	35,028	$74.00/$142.21
Natural Gas	01/2012 to 03/2012	137,940	$7.00/$15.55
Natural Gas	04/2012 to 06/2012	134,203	$6.00/$13.60
Natural Gas	07/2012 to 09/2012	130,173	$6.00/$14.45
Natural Gas	10/2012 to 12/2012	126,613	$7.00/$13.40

The collared hedges shown 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 hedges outstanding as of December 31, 2011, a hypothetical upward or downward shift of $10.00 per Bbl in the NYMEX forward curve as of December 31, 2011 would cause a decrease or increase, respectively, of $83.1 million in our commodity derivative gain . For the natural gas hedges outstanding as of December 31, 2011, a hypothetical $1.00 per Mcf upward or downward shift in the NYMEX forward curve as of December 31, 2011 would cause a decrease or increase, respectively, in our commodity derivative gain of $0.3 million.

We have various fixed price gas sales contracts with end users for a portion of the natural gas we produce in Colorado, Michigan and Utah. Our estimated future production volumes to be sold under these fixed price contracts as of January 31, 2012 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	01/2012 to 03/2012	576,963	$5.30
Natural Gas	04/2012 to 06/2012	461,296	$5.41
Natural Gas	07/2012 to 09/2012	465,630	$5.41
Natural Gas	10/2012 to 12/2012	398,667	$5.46
Natural Gas	01/2013 to 03/2013	360,000	$5.47
Natural Gas	04/2013 to 06/2013	364,000	$5.47
Natural Gas	07/2013 to 09/2013	368,000	$5.47
Natural Gas	10/2013 to 12/2013	368,000	$5.47
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

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. We have entered into certain contracts for oil field goods and services with price adjustment clauses that are linked to changes in NYMEX crude oil prices to reduce our exposure to paying higher than the market rates for these goods and services in a climate of declining oil prices. We have determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host contracts, and we have therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in the consolidated financial statements. These embedded commodity derivative contracts have not been designated as hedges, and therefore all changes in fair value since inception have been recorded immediately to earnings.

As of December 31, 2011, we had two contracts with drilling rig companies, whereby the rig day rates increased or decreased along with changes in the price of NYMEX crude oil. These drilling rig contracts have termination dates of March 2014 and September 2014. For these embedded commodity derivative contracts, a hypothetical upward or downward shift of $10.00 per Bbl in the NYMEX forward curve as of December 31, 2011 would cause a decrease or increase, respectively, of $1.6 million in our commodity derivative gain.

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In May 2011, we entered into a long-term contract to purchase CO2 from 2015 through 2029 for use in our enhanced oil recovery project at our North Ward Estes field in Texas. 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 $10.00 per Bbl in the NYMEX forward curve as of December 31, 2011 would cause a decrease or increase, respectively, of $13.5 million in our commodity derivative gain.

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. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate Senior Subordinated Notes. At December 31, 2011, our outstanding principal balance under our credit agreement was $780.0 million, and the weighted average interest rate on the outstanding principal balance was 2.4%. At December 31, 2011, the carrying amount approximated fair market value. Assuming a constant debt level of $780.0 million, the cash flow impact resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $7.5 million over a 12-month time period.

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Item 8. Financial Statements and Supplementary Data

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, 2011 using the criteria set forth in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on this assessment, our management believes that, as of December 31, 2011, 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, 2011 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.

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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 internal control over financial reporting of Whiting Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2011, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's 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, 2011, based on the criteria established in Internal Control — Integrated Framework 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, 2011 of the Company and our report dated February 23, 2012 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2012

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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, 2011 and 2010, and the related consolidated statements of income, cash flows, and equity and comprehensive income for each of the three years in the period ended December 31, 2011. 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, 2011 and 2010, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2011, 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.

As discussed in Note 1 to the consolidated financial statements, the Company changed its method of oil and gas reserve estimation and related required disclosures in 2009 with implementation of new accounting guidance.

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, 2011, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2012 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2012

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

	December 31, 2011	December 31, 2010
ASSETS		
Current assets:		
Cash and cash equivalents	$ 15,811	$ 18,952
Accounts receivable trade, net	262,515	199,713
Prepaid expenses and other	20,377	14,878
Total current assets	298,703	233,543
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	7,221,550	5,661,619
Unproved properties	354,774	226,336
Other property and equipment	150,933	98,092
Total property and equipment	7,727,257	5,986,047
Less accumulated depreciation, depletion and amortization	(2,088,517)	(1,630,824)
Total property and equipment, net	5,638,740	4,355,223
Debt issuance costs	33,306	34,226
Other long-term assets	74,860	25,785
TOTAL ASSETS	$ 6,045,609	$ 4,648,777
LIABILITIES AND EQUITY		
Current liabilities:		
Accounts payable trade	$ 56,673	$ 35,016
Accrued capital expenditures	142,827	84,789
Accrued liabilities and other	157,214	153,062
Revenues and royalties payable	103,894	82,124
Taxes payable	31,195	30,291
Derivative liabilities	73,647	69,375
Deferred income taxes	1,584	4,548
Total current liabilities	567,034	459,205
Long-term debt	1,380,000	800,000
Deferred income taxes	823,643	539,071
Derivative liabilities	47,763	95,256
Production Participation Plan liability	80,659	81,524
Asset retirement obligations	61,984	76,994
Deferred gain on sale	29,619	41,460
Other long-term liabilities	25,776	23,952
Total liabilities	3,016,478	2,117,462
Commitments and contingencies		
Equity:		
Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 172,391 shares issued and outstanding as of December 31, 2011 and 172,500 shares issued and outstanding as of December 31, 2010, aggregate liquidation preference of $17,239,100 at	-	-

December 31, 2011				
Common stock, $0.001 par value, 300,000,000 shares authorized; 118,105,279 issued and 117,380,884 outstanding as of December 31, 2011, 117,967,876 issued and 117,098,506 outstanding as of December 31, 2010 (1)		118		59
Additional paid-in capital		1,554,223		1,549,822
Accumulated other comprehensive income		240		5,768
Retained earnings		1,466,276		975,666
Total Whiting shareholders' equity		3,020,857		2,531,315
Noncontrolling interest		8,274		-
Total equity		3,029,131		2,531,315
TOTAL LIABILITIES AND EQUITY	$	6,045,609	$	4,648,777

(1) All common share amounts (except par value and par value per share amounts) have been retroactively restated as of December 31, 2010 to reflect the Company's two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

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,		
	2011	2010	2009
REVENUES AND OTHER INCOME:			
Oil and natural gas sales	$1,860,146	$1,475,288	$917,541
Gain on hedging activities	8,758	23,198	38,776
Amortization of deferred gain on sale	13,937	15,613	16,596
Gain on sale of properties	16,313	1,388	5,947
Interest income and other	468	612	500
Total revenues and other income	1,899,622	1,516,099	979,360
COSTS AND EXPENSES:			
Lease operating	305,487	268,348	237,270
Production taxes	139,190	103,880	64,672
Depreciation, depletion and amortization	468,203	393,897	394,792
Exploration and impairment	84,644	59,371	73,014
General and administrative	84,985	64,694	42,357
Interest expense	62,516	59,078	64,608
Loss on early extinguishment of debt	-	6,235	-
Change in Production Participation Plan liability	(865)	12,091	3,267
Commodity derivative (gain) loss, net	(24,857)	7,062	262,215
Total costs and expenses	1,119,303	974,656	1,142,195
INCOME (LOSS) BEFORE INCOME TAXES	780,319	541,443	(162,835)
INCOME TAX EXPENSE (BENEFIT):			
Current	3,853	4,979	236
Deferred	284,838	199,811	(56,189)
Total income tax expense (benefit)	288,691	204,790	(55,953)
NET INCOME (LOSS)	491,628	336,653	(106,882)
Net loss attributable to noncontrolling interest	59	-	-
NET INCOME (LOSS) AVAILABLE TO SHAREHOLDERS	491,687	336,653	(106,882)
Preferred stock dividends and inducement premium	(1,077)	(63,970)	(10,302)
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$490,610	$272,683	$(117,184)
EARNINGS (LOSS) PER COMMON SHARE (1):			
Basic	$4.18	$2.57	$(1.18)
Diluted	$4.14	$2.55	$(1.18)
WEIGHTED AVERAGE SHARES OUTSTANDING (1):			
Basic	117,345	106,338	100,088
Diluted	118,668	107,846	100,088

(1) All share and per share amounts have been retroactively restated for the 2009 and 2010 periods to reflect the Company's two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

See notes to consolidated financial statements.

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

	Year Ended December 31,		
	2011	2010	2009
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$491,628	$336,653	$(106,882)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	468,203	393,897	394,792
Deferred income tax expense (benefit)	284,838	199,811	(56,189)
Amortization of debt issuance costs and debt discount	8,682	10,592	11,026
Stock-based compensation	13,509	8,871	7,650
Amortization of deferred gain on sale	(13,937)	(15,613)	(16,596)
Gain on sale of properties	(16,313)	(1,388)	(5,947)
Undeveloped leasehold and oil and gas property impairments	38,783	26,525	26,139
Exploratory dry hole costs	4,924	3,819	18,212
Loss on early extinguishment of debt	-	6,235	-
Change in Production Participation Plan liability	(865)	12,091	3,267
Unrealized (gain) loss on derivative contracts	(63,093)	(40,736)	218,255
Other non-current	(13,512)	(4,013)	955
Changes in current assets and liabilities:			
Accounts receivable trade	(62,802)	(47,631)	(27,336)
Prepaid expenses and other	(3,771)	(3,387)	30,024
Accounts payable trade and accrued liabilities	33,135	66,663	(55,917)
Revenues and royalties payable	21,770	35,797	11,221
Taxes payable	904	9,103	1,150
Net cash provided by operating activities	1,192,083	997,289	453,824
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash acquisition capital expenditures	(250,041)	(184,729)	(97,920)
Drilling and development capital expenditures	(1,554,271)	(739,047)	(506,089)
Proceeds from sale of oil and gas properties	69,276	9,202	80,462
Issuance of note receivable	(25,000)	-	-
Net cash used in investing activities	(1,760,036)	(914,574)	(523,547)
CASH FLOWS FROM FINANCING ACTIVITIES:	-		
Issuance of 6.5% Senior Subordinated Notes due 2018	-	350,000	-
Redemption of 7.25% Senior Subordinated Notes due 2012	-	(150,000)	-
Redemption of 7.25% Senior Subordinated Notes due 2013	-	(223,988)	-
Issuance of 6.25% convertible perpetual preferred stock	-	-	334,112
Issuance of common stock	-	-	234,753
Premium on induced conversion of 6.25% convertible perpetual preferred stock	-	(47,529)	-
Contributions from noncontrolling interest	2,500		
Preferred stock dividends paid	(1,077)	(16,441)	(10,302)
Long-term borrowings under credit agreement	1,760,000	1,150,000	490,000

Repayments of long-term borrowings under credit agreement	(1,180,000)	(1,110,000)	(950,000)
Repayments to Alliant Energy Corporation	(1,871)	(1,615)	(2,701)
Debt issuance costs	(5,691)	(20,471)	(23,141)
Restricted stock used for tax withholdings	(9,049)	(5,679)	(662)
Net cash provided by (used in) financing activities	564,812	(75,723)	72,059

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,		
	2011	2010	2009
NET CHANGE IN CASH AND CASH EQUIVALENTS	$(3,141)	$6,992	$2,336
CASH AND CASH EQUIVALENTS:			
Beginning of period	18,952	11,960	9,624
End of period	$15,811	$18,952	$11,960
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid (refunded) for income taxes	$4,065	$6,181	$(1,408)
Cash paid for interest, net of amounts capitalized	$53,761	$46,332	$52,754
NONCASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$142,827	$84,789	$29,998
NONCASH FINANCING ACTIVITIES:			
Contributions from noncontrolling interest	$5,833	$-	$-
Issuance of common stock related to the induced conversion of preferred stock	$-	$317,406	$-
Preferred stock cancelled in connection with its induced conversion	$-	$(317,406)	$-

See notes to consolidated financial statements. (Concluded)

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WHITING PETROLEUM CORPORATION
CONSOLIDATED STATEMENTS OF EQUITY AND COMPREHENSIVE INCOME
(In thousands)

	Preferred Stock		Common Stock (1)		Additional Paid-in	Accumulated Other Comprehensive Income (Loss)	Retained	Total Whiting Shareholders'	Noncontrolling	Total
	Shares	Amount	Shares	Amount	Capital		Earnings	Equity	Interest	Equity
BALANCES-January 1, 2009	-	$-	85,164	$43	$971,310	$17,271	$820,167	$1,808,791	$-	$1,808,79
Net loss	-	-	-	-	-	-	(106,882)	(106,882)	-	(106,88
Change in derivative fair values, net of taxes of $7,799	-	-	-	-	-	13,348	-	13,348	-	13,348
Realized gain on settled derivatives, net of taxes of $4,933	-	-	-	-	-	(8,517)	-	(8,517)	-	(8,517
Ineffectiveness loss on hedging activities, net of taxes of $8,355	-	-	-	-	-	14,300	-	14,300	-	14,300
OCI amortization on de-designated hedges, net of taxes of $9,337	-	-	-	-	-	(15,989)	-	(15,989)	-	(15,989
Total comprehensive loss								(103,740)	-	
Issuance of 6.25% convertible perpetual preferred stock	3,450	3	-	-	334,109	-	-	334,112	-	334,112
Issuance of stock, secondary offering	-	-	16,900	8	234,745	-	-	234,753	-	234,753
Restricted stock issued	-	-	728	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(10)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(54)	-	(662)	-	-	(662)	-	(662
Tax effect from restricted stock vesting	-	-	-	-	(517)	-	-	(517)	-	(517
Stock-based compensation	-	-	-	-	7,650	-	-	7,650	-	7,650
Preferred dividends paid	-	-	-	-	-	-	(10,302)	(10,302)	-	(10,302
BALANCES-December 31, 2009	3,450	3	102,728	51	1,546,635	20,413	702,983	2,270,085	-	2,270,0
Net income	-	-	-	-	-	-	336,653	336,653	-	336,653
OCI amortization on de-designated hedges, net of taxes of $8,553	-	-	-	-	-	(14,645)	-	(14,645)	-	(14,645

Total comprehensive income								322,008	-	
Induced conversion of convertible perpetual preferred stock	(3,277)	(3)	15,098	8	(5)	-	(47,529)	(47,529)	-	(47,529
Restricted stock issued	-	-	325	-	-	-	-	-	-	-
Restricted stock forfeited	-	-	(27)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	-	-	(156)	-	(5,679)	-	-	(5,679)	-	(5,679
Stock-based compensation	-	-	-	-	8,871	-	-	8,871	-	8,871
Preferred dividends paid	-	-	-	-	-	-	(16,441)	(16,441)	-	(16,441
BALANCES-December 31, 2010	173	-	117,968	59	1,549,822	5,768	975,666	2,531,315	-	2,531,3
Net income	-	-	-	-	-		491,687	491,687	(59)	491,628
OCI amortization on de-designated hedges, net of taxes of $3,230	-	-	-	-	-	(5,528)	-	(5,528)	-	(5,528
Total comprehensive income								486,159	(59)	
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	$3,029,1

(1) All common share amounts (except par values) have been retroactively restated for all periods presented to reflect the Company’s two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

See notes to consolidated financial statements.

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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 acquires, exploits, develops and explores for crude oil, natural gas and natural gas liquids primarily in the Rocky Mountains, Permian Basin, Mid-Continent, Michigan and Gulf Coast 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 pursuant to Whiting’s 15.8% ownership interest. 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 consists 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, 2011 and 2010, the Company had an allowance for doubtful accounts of \$1.7 million and \$0.4 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 2011, 2010 and 2009, the Company capitalized interest of $3.6 million, $2.9 million and $3.4 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 CO_2, for enhanced oil recovery activities that are incurred 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 immediately. 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 CO_2 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 mainly of materials and supplies inventories which are not depreciated. Also included in other property and equipment are an oil pipeline, furniture and fixtures, 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.

Debt Issuance Costs—Debt issuance costs related to the Company's 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 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 is reclassified to net income when the underlying forecasted transaction occurs. Any ineffective portion of such hedges was recognized in commodity derivative (gain) loss, net as it occurred. The ineffective portion of the hedge, if any, is calculated as the difference between the change in fair value of the derivative and the estimated change in cash flows from the item hedged. 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.

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The Company formally documents all relationships between hedging instruments and hedged items, as well as the risk management objectives and strategy for undertaking the hedge. This process includes specific identification of the hedging instrument and the hedged item, the nature of the risk being hedged and the manner in which the hedging instrument's effectiveness will be assessed. To designate a derivative as a cash flow hedge, the Company documents at the hedge's inception its assessment as to whether the derivative will be highly effective in offsetting expected changes in cash flows from the item hedged. This assessment, which is updated at least quarterly, is generally based on the most recent relevant historical correlation between the derivative and the item hedged. If, during the derivative's term, the Company determines that the hedge is no longer highly effective, hedge accounting is prospectively discontinued.

Deferred Gain on Sale—The deferred gain on sale of 11,677,500 Whiting USA Trust I units is amortized to income based on the units-of-production method.

Revenue Recognition—Oil and gas revenues are recognized when production is sold to a purchaser at a fixed or determinable price, when delivery has occurred and title has transferred, and if the 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, 2011 and 2010, the Company was in a net under (over) produced imbalance position of (13,716) Mcf and 12,666 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.

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, natural gas and natural gas liquids. 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 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 of the Company's total oil and gas sales to each significant purchaser for the years ended December 31, 2011, 2010 and 2009:

	2011	2010	2009
Shell Trading US	13%	17%	18%
Plains Marketing LP (1)	27%	16%	15%
Nexen Pipeline USA, Inc. (1)	-	13%	8%
EOG Resources, Inc.	7%	10%	13%

(1) Effective December 30, 2010, Plains Marketing LP acquired Nexen Pipeline USA, Inc.

Commodity derivative contracts held by the Company are with ten counterparties, all of which are part of Whiting's credit facility and all of which have investment-grade ratings from Moody's and Standard & Poor. As of December 31, 2011, outstanding derivative contracts with JP Morgan Chase Bank, N.A., KeyBank National Association, and Wells Fargo Bank, N.A. represent 47%, 18% and 13%, respectively, of total crude oil volumes hedged, while outstanding derivative contracts with JP Morgan Chase Bank, N.A. represent 100% of total gas volumes hedged.

Adopted and Recently Issued Accounting Pronouncements—In December 2008, the SEC issued Modernization of Oil and Gas Reporting: Final Rule, which published the final rules and interpretations updating its oil and gas reporting requirements. The final rule includes updates to definitions in the existing oil and gas rules to make them consistent with the petroleum resource management system, which is a widely accepted standard for the management of petroleum resources that was developed by several industry organizations. Key revisions include the ability to include nontraditional resources in reserves, the use of new technology for determining reserves, permitting disclosure of probable and possible reserves, and changes to the pricing used to determine reserves in that companies must use a 12-month average price. The average is calculated using the first-day-of-the-month price for each of the 12 months that make up the reporting period. The Company adopted the new rules effective December 31, 2009, and as a result, Whiting (i) prepared its reserve estimates as of December 31, 2009, 2010 and 2011 based on the new reserve definitions, (ii) reported its year-end probable and possible reserve quantities in Item I and Item II of this annual report, (iii) has estimated its December 31, 2009, 2010 and 2011 reserve quantities using the 12-month average price and (iv) included additional disclosures as required by the new rule. As a result of the change in reserve pricing from using year-end oil and gas prices to now using 12-month average prices, the Company's total proved reserves at December 31, 2009 were 20.4 MMBOE lower than they would have otherwise been if year-end oil and gas prices were used. Oil and gas reserve quantities or their values are a significant component of the Company's depreciation, depletion and amortization, asset retirement obligation, impairment analyses and Production Participation Plan liability calculations. Due to the number of estimates that rely upon reserve quantities and values, any significant changes to the Company's oil and gas reserves has a pervasive effect on Whiting's consolidated financial statements, and it is therefore impracticable to estimate the effect that the adoption of the SEC's Modernization of Oil and Gas Reporting: Final Rule had on the Company's financial statements.

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In January 2010, the FASB issued Accounting Standards Update No. 2010-03, Oil and Gas Reserve Estimation and Disclosures (“ASU 2010-03”), which provides amendments to FASB ASC topic Extractive Activities-Oil and Gas. The objective of ASU 2010-03 is to align the oil and gas reserve estimation and disclosure requirements of the FASB ASC with the requirements in the SEC’s Modernization of Oil and Gas Reporting: Final Rule. The Company adopted ASU 2010-03 effective December 31, 2009, and as a result, Whiting (i) has estimated its December 31, 2009, 2010 and 2011 reserve quantities using the 12-month average price, (ii) prepared its reserve estimates as of December 31, 2009, 2010 and 2011 based on the new and amended reserve definitions in ASU 2010-03 that conform to the SEC’s revised reserve definitions, and (iii) reported proved undeveloped reserve quantities in Disclosure About Oil and Gas Producing Activities. As a result of the change in reserve pricing from using year-end oil and gas prices to now using 12-month average prices, the Company’s total proved reserves at December 31, 2009 were 20.4 MMBOE lower than they would have otherwise been if year-end oil and gas prices were used. Oil and gas reserve quantities or their values are a significant component of the Company’s depreciation, depletion and amortization, asset retirement obligation, proved property impairment analyses and Production Participation Plan liability calculations. Due to the number of estimates that rely upon reserve quantities and values, any significant changes to the Company’s oil and gas reserves has a pervasive effect on Whiting’s consolidated financial statements, and it is therefore impracticable to estimate the effect that the adoption of ASU 2010-03 had on the Company’s financial statements.

In December 2010, the FASB issued Accounting Standards Update No. 2010-29, Business Combinations: Disclosure of Supplementary Pro Forma Information for Business Combinations (“ASU 2010-29”), which provides amendments to FASB ASC Topic 805, Business Combinations. The objective of ASU 2010-29 is to clarify and expand the pro forma revenue and earnings disclosure requirements for business combinations. ASU 2010-29 was effective for fiscal years beginning after December 15, 2010. The Company adopted ASU 2010-29 effective January 1, 2011, which did not have an impact on the Company’s consolidated financial statements.

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. These amendments are not expected to have a significant impact on companies applying GAAP. ASU 2011-04 is effective for interim and annual periods beginning after December 15, 2011. The adoption of this standard will not have an impact on the Company’s consolidated financial statements other than additional disclosures.

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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 should 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 defers 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 adoption of these standards will not have an impact on the Company's consolidated financial statements other than requiring the Company to present its statements of comprehensive income separately from its statements of equity, as these statements are currently 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. ASU 2011-11 is effective for interim and annual reporting periods beginning on or after January 1, 2013 and should be applied retrospectively. The adoption of this standard will not have an impact on the Company's consolidated financial statements.

2. ACQUISITIONS AND DIVESTITURES

2011 Acquisitions

On July 28, 2011, the Company completed the acquisition of approximately 23,400 net acres and one well in the Missouri Breaks prospect 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 Billings and Stark Counties, 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.

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2010 Activity

In September 2010, Whiting acquired operated interests in 19 producing oil and gas wells, undeveloped acreage, and gathering lines, all of which are located on approximately 20,400 gross (16,100 net) acres in Weld County, Colorado. The aggregate purchase price was $19.2 million; substantially all of which was allocated to the oil and gas properties and acreage acquired. Disclosures of pro forma revenues and net income for the 19 wells acquired are not material and have not been presented accordingly.

In August 2010, Whiting acquired oil and gas leasehold interests covering approximately 112,000 gross (90,200 net) acres in the Montana portion of the Williston Basin for $26.0 million. The undeveloped acreage is located in Roosevelt and Sheridan counties.

There were no significant divestitures during the year ended December 31, 2010.

2009 Acquisitions

During 2009, Whiting acquired additional royalty and overriding royalty interests in the North Ward Estes field and various other fields in the Permian Basin in two separate transactions with private owners. Also included in these transactions were contractual rights, including an option to participate for an aggregate 10% working interest and right to back in after payout for an additional aggregate 15% working interest in the development of deeper pay zones on acreage under and adjoining the North Ward Estes field.

Whiting completed the first acquisition of additional royalty and overriding royalty interests in November 2009 for $38.7 million in cash consideration. The Company completed the second acquisition of additional royalty and overriding royalty interests in December 2009 for $27.4 million in cash. Reserves attributable to royalty and overriding royalty interests are not burdened by operating expenses or any additional capital costs, including CO2 costs, which are paid by the working interest owners. These two acquisitions were funded primarily from net cash provided by operating activities. Substantially all of the purchase price was allocated to the properties acquired.

2009 Participation Agreement

In June 2009, Whiting entered into a participation agreement with a privately held independent oil company covering twenty-five 1,280-acre units and one 640-acre unit located primarily in the western portion of the Sanish field in Mountrail County, North Dakota. Under the terms of the agreement, the private company agreed to pay 65% of Whiting’s net drilling and well completion costs to receive 50% of Whiting’s working interest and net revenue interest in the first and second wells planned for each of the units. Pursuant to the agreement, Whiting will remain the operator for each unit.

At the closing of the agreement, the private company paid Whiting $107.3 million, representing $6.4 million for acreage costs, $65.8 million for 65% of Whiting’s cost in 18 wells drilled or drilling and $35.1 million for a 50% interest in Whiting’s Robinson Lake gas plant and oil and gas gathering system, resulting in a pre-tax gain on sale of $4.6 million. Whiting used these proceeds to repay a portion of the debt outstanding under its credit agreement.

3. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2011 and 2010 (in thousands):

	December 31, 2011	December 31, 2010
Credit agreement	$ 780,000	$ 200,000
6.5% Senior Subordinated Notes due 2018	350,000	350,000
7% Senior Subordinated Notes due 2014	250,000	250,000
Total debt	$ 1,380,000	$ 800,000

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. As of December 31, 2011, this credit facility had a borrowing base of $1.5 billion with $718.6 million of available borrowing capacity, which is net of $780.0 million in borrowings and $1.4 million in letters of credit outstanding. The credit agreement provides for interest only payments until April 2016, when the agreement expires and all outstanding borrowings are due. In October 2011, Whiting Oil and Gas entered into an amendment to its existing credit agreement that increased the borrowing base under the facility from $1.1 billion to $1.5 billion.

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 its 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, 2011, $48.6 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 are included as a component of interest expense. At December 31, 2011, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.4%.

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, which include the payment of dividends on the Company's 6.25% convertible perpetual preferred stock, the credit agreement also restricts our 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, 2011, total restricted net assets were $2,801.3 million, and the amount of retained earnings free from restrictions was $16.4 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 4.25 to 1.0 for quarters ending prior to and on December 31, 2012 and 4.0 to 1.0 for quarters ending March 31, 2013 and thereafter 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, 2011.

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The obligations of Whiting Oil and Gas under the amended 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 Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due February 2014. The estimated fair value of these notes was $265.3 million as of December 31, 2011, based on quoted market prices for these same debt securities.

Redemption of 7.25% Senior Subordinated Notes Due 2012 and 2013—In September 2010, the Company paid $383.5 million to redeem $150.0 million of its 7.25% Senior Subordinated Notes due 2012 and $220.0 million of its 7.25% Senior Subordinated Notes due 2013, which consisted of a redemption price of 100.00% for the 2012 notes and 101.8125% for the 2013 notes and included the payment of accrued and unpaid interest on such notes. The Company financed the redemption of the 2012 and 2013 notes with borrowings under its credit agreement. As a result of the redemption, Whiting recognized a $6.2 million loss on early extinguishment of debt, which consisted of a cash charge of $4.0 million related to the redemption premium on the 2013 notes and a non-cash charge of $2.2 million related to the acceleration of debt discounts and unamortized debt issuance costs.

Issuance of 6.5% Senior Subordinated Notes Due 2018—In September 2010, the Company issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. The Company used the net proceeds from this issuance to repay a portion of the debt, which was borrowed to redeem its 2012 and 2013 notes, outstanding under its credit agreement. The estimated fair value of these notes was $364.4 million as of December 31, 2011, based on quoted market prices for these same debt securities.

The notes are unsecured obligations of Whiting Petroleum Corporation and are subordinated to all of the Company's senior debt, which currently consists of Whiting Oil and Gas' credit agreement. The Company's obligations under the 2014 notes are fully, unconditionally, jointly and severally guaranteed by the Company's 100%-owned subsidiaries, Whiting Oil and Gas and Whiting Programs, Inc. (the "2014 Guarantors"). Additionally, the Company's obligations under the 2018 notes are fully, unconditionally, jointly and severally guaranteed by the Company's 100%-owned subsidiary, Whiting Oil and Gas (collectively with the 2014 Guarantors, the "Guarantors"). Any subsidiaries other than the Guarantors are minor subsidiaries as defined by Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission. Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in guarantor subsidiaries.

4. ASSET RETIREMENT OBLIGATIONS

The Company's asset retirement obligations represent the 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, 2011 and 2010 were $7.7 million and $6.1 million, respectively, and are included in accrued liabilities and other. Revisions to the liability could 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, 2011 and 2010 (in thousands):

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	Year Ended December 31, 2011	2010
Asset retirement obligation at January 1	$ 83,083	$ 77,186
Additional liability incurred	4,882	3,518
Revisions in estimated cash flows	(20,049)	5,548
Accretion expense	8,016	7,223
Obligations on sold properties	(790)	(5,542)
Liabilities settled	(5,421)	(4,850)
Asset retirement obligation at December 31	$ 69,721	$ 83,083

5. 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, 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 and 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 Whiting USA Trust I (the "Trust") derivatives, entered into to hedge forecasted crude oil and natural gas production revenues, as of January 31, 2012.

Whiting Petroleum Corporation

	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jan – Dec 2012	11,805,091	384,002	$66.64 - $108.55	$6.50 - $14.27
Jan – Nov 2013	3,090,000	-	$47.64 - $ 89.90	n/a
Total	14,895,091	384,002		

Derivatives Conveyed to Whiting USA Trust I. In connection with the Company's conveyance in April 2008 of a term net profits interest to the Trust and related sale of 11,677,500 Trust 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 the Trust, and therefore such payments will be included in the Trust's calculation of net proceeds. Under the terms of the aforementioned conveyance, Whiting retains 10% of the net proceeds from the underlying properties. Whiting's retention of 10% of these net proceeds, combined with its ownership of 2,186,389 Trust units, results in third-party public holders of Trust units receiving 75.8%, and Whiting retaining 24.2%, of the future economic results of commodity derivative contracts conveyed to the Trust. 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 assets.

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The 24.2% portion of Trust derivatives that Whiting has retained the economic rights to (and which are also included in the table above) are as follows:

	Whiting Petroleum Corporation			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jan – Dec 2012	105,091	384,002	$74.00 - $141.72	$6.50 - $14.27

The 75.8% portion of Trust derivative contracts of which Whiting has transferred the economic rights to third-party public holders of Trust units (and which have not been reflected in the above tables) are as follows:

	Third-party Public Holders of Trust Units			
	Contracted Volumes		Weighted Average NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jan – Dec 2012	329,171	1,202,785	$74.00 - $141.72	$6.50 - $14.27

Discontinuance of Cash Flow Hedge Accounting—Prior to April 1, 2009, the Company designated a portion of its commodity derivative contracts as cash flow hedges, whose unrealized fair value gains and losses were recorded to other comprehensive income. Effective April 1, 2009, however, 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 accumulated other comprehensive income as of the de-designation date and are being reclassified into earnings as the original hedged transactions affect income. As of December 31, 2011, accumulated other comprehensive income amounted to $0.4 million ($0.2 million net of tax), which consisted entirely of unrealized deferred gains and losses on commodity derivative contracts that had been previously designated as cash flow hedges. During the next twelve months, the Company expects to reclassify into earnings from accumulated other comprehensive income net after-tax gains of $1.5 million related to de-designated commodity hedges. Currently, the Company recognizes 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.

Embedded Commodity Derivative Contracts—As of December 31, 2011, Whiting had entered into certain contracts for oil field goods or services, whereby the price adjustment clauses for such goods or services are linked to changes in NYMEX crude oil prices. The Company has determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host contracts, and the Company has therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in the consolidated financial statements.

Drilling Rig Contracts. As of December 31, 2011, Whiting had entered into two contracts with drilling rig companies, whereby the rig day rates included price adjustment clauses that are linked to changes in NYMEX crude oil prices. These drilling rig contracts have termination dates of March 2014 and September 2014. The price adjustment formulas in the rig contracts stipulate that with every $10 increase or decrease in the price of NYMEX crude, the cost of drilling rig day rates to the Company will likewise increase or decrease by specific dollar amounts as set forth in each of the individual contracts. As of December 31, 2011, the aggregate estimated fair value of the embedded derivatives in these drilling rig contracts was an asset of $0.6 million.

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As global crude oil prices increase or decrease, the demand for drilling rigs in North America similarly increases and decreases. Because the supply of onshore drilling rigs in North America is fairly inelastic, these changes in rig demand cause drilling rig day rates to increase or decrease in tandem with crude oil price fluctuations. When the Company enters into a long-term drilling rig contract that has a fixed rig day rate, which does not increase or decrease with changes in oil prices, the Company is exposed to the risk of paying higher than the market day rate for drilling rigs in a climate of declining oil prices. This in turn could have a negative impact on the Company's oil and gas well economics. As a result, the Company reduces its exposure to this risk by entering into certain drilling contracts which have day rates that fluctuate in tandem with changes in oil prices.

CO_2 Purchase Contract. In May 2011, Whiting entered into a long-term contract to purchase CO_2 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. The price per Mcf of CO_2 purchased under this agreement increases or decreases as the average price of NYMEX crude oil likewise increases or decreases. As of December 31, 2011, the estimated fair value of the embedded derivative in this CO_2 purchase contract was an asset of $13.0 million.

Although CO_2 is not a commodity that is actively traded on a public exchange, the market price for CO_2 generally fluctuates in tandem with increases or decreases in crude oil prices. When Whiting enters into a long-term CO_2 purchase contract where the price of CO_2 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 CO_2 in a climate of declining oil and CO_2 prices. This in turn could have a negative impact on the project economics of the Company's CO_2 flood at North Ward Estes. As a result, the Company reduces its exposure to this risk by entering into certain CO_2 purchase contracts which have prices that fluctuate along with changes in crude oil prices.

Derivative Instrument Reporting—All derivative instruments are recorded on the consolidated balance sheet at fair value, other than derivative instruments that meet the "normal purchase normal sale" exclusion. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands):

		Fair Value	
Not Designated as ASC 815 Hedges	Balance Sheet Classification	December 31, 2011	December 31, 2010
Derivative assets:			
Commodity contracts	Prepaid expenses and other	$ 5,719	$ 4,231
Embedded commodity contracts	Prepaid expenses and other	240	-
Commodity contracts	Other long-term assets	-	3,961
Embedded commodity contracts	Other long-term assets	13,347	-
Total derivative assets		$ 19,306	$ 8,192
Derivative liabilities:			
Commodity contracts	Current derivative liabilities	$ 73,647	$ 69,375
Commodity contracts	Non-current derivative liabilities	47,763	95,256
Total derivative liabilities		$ 121,410	$ 164,631

The following tables summarize the effects of commodity derivatives instruments on the consolidated statements of income for the twelve months ended December 31, 2011 and 2010 (in thousands):

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain Reclassified from OCI into Income (Effective Portion) Year Ended December 31, 2011	2010
Commodity contracts	Gain on hedging activities	$ 8,758	$ 23,198

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Not Designated as ASC 815 Hedges	Income Statement Classification	(Gain) Loss Recognized in Income Year Ended December 31, 2011	2010
Commodity contracts	Commodity derivative (gain) loss, net	$ (11,270)	$ 7,062
Embedded commodity contracts	Commodity derivative (gain) loss, net	(13,587)	-
Total		$ (24,857)	$ 7,062

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 current or former lenders under Whiting's credit agreement. At the time Whiting enters into derivative contracts, 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 large 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.

6. 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.

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, 2011 and 2010, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

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	Level 1	Level 2	Level 3	Total Fair Value December 31, 2011
Financial Assets				
Commodity derivatives - current	$ -	$ 5,719	$ -	$ 5,719
Embedded commodity derivatives - current	-	240	-	240
Embedded commodity derivatives - non-current	-	367	12,980	13,347
Total financial assets	$ -	$ 6,326	$ 12,980	$ 19,306
Financial Liabilities				
Commodity derivatives - current	$ -	$ 73,647	$ -	$ 73,647
Commodity derivatives - non-current	-	47,763	-	47,763
Total financial liabilities	$ -	$ 121,410	$ -	$ 121,410

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2010
Financial Assets				
Commodity derivatives - current	$ -	$ 4,231	$ -	$ 4,231
Commodity derivatives - non-current	-	3,961	-	3,961
Total financial assets	$ -	$ 8,192	$ -	$ 8,192
Financial Liabilities				
Commodity derivatives - current	$ -	$ 69,375	$ -	$ 69,375
Commodity derivatives - non-current	-	95,256	-	95,256
Total financial liabilities	$ -	$ 164,631	$ -	$ 164,631

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 primarily of costless collars for crude oil and natural gas. The Company's costless collars are valued based on a market approach. These models consider various assumptions, including 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 counterparties' valuations to assess the reasonableness of its own valuations.

Embedded Commodity Derivatives. Embedded commodity derivatives relate to long-term drilling rig contracts as well as a CO_2 purchase contract, which all have price adjustment clauses that are linked to changes in NYMEX crude oil prices. Whiting has determined that the portions of these contracts linked to NYMEX oil prices are not clearly and closely related to the host drilling contracts, and the Company has therefore bifurcated these embedded pricing features from their host contracts and reflected them at fair value in its consolidated financial statements. These embedded commodity derivatives are valued based on a market approach. These models consider various assumptions, including quoted forward prices for commodities, LIBOR discount rates and either the Company's or the counterparty's nonperformance risk, as appropriate.

The assumptions used in the valuation of the drilling rig contracts 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 the fair value measurements of the drilling rig contracts are therefore designated as Level 2 within the valuation hierarchy.

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The assumptions used in the CO2 contract valuation, however, 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.

There were no recurring fair value measurements designated as Level 3 during 2010. 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, 2011 (in thousands):

	Year Ended December 31, 2011
Fair value asset (liability), beginning of period	$ -
Unrealized gains (losses) on embedded commodity derivative contracts included in earnings(1)	11,081
Transfers into (out of) Level 3(2)	1,899
Fair value asset (liability), end of period	$ 12,980

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

(2) With respect to forward prices for NYMEX crude oil where there is a lack of price transparency in certain future periods during the term of the CO2 contract, such unobservable oil price inputs became significant to the valuation methodology, and the contract's fair value was therefore transferred from Level 2 to Level 3 within the valuation hierarchy.

Nonrecurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its nonrecurring, non-financial measurements. 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 table presents information about the Company's non-financial assets and liabilities measured at fair value on a nonrecurring basis as of December 31, 2011, and indicates the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

		Fair Value Measurements Using			Loss (Before Tax) Year Ended December 31, 2011
	Net Carrying Value as of December 31, 2011	Level 1	Level 2	Level 3	
Proved property impairments	$ 4,853	-	-	$ 1,612	$ 3,241

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

Proved Property Impairments. The Company reviews oil and gas properties for potential impairment by comparing future net undiscounted cash flows to the net book value at the end of each period. If the net capitalized cost exceeds 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. The Company uses estimated future cash flows, which are based on an income approach, discounted at a rate consistent with those used to evaluate cash flows of similar assets. Given the unobservable nature of the inputs, proved oil and gas property impairments are deemed to use Level 3 inputs. The Company did not recognize any impairment write-downs associated with its proved oil and gas properties during the year ended December 31, 2010.

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7. 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 2%-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, 2011, 2010 and 2009 amounted to $34.1 million, $27.7 million and $15.8 million, respectively, charged to general and administrative expense and $4.2 million, $3.7 million and $2.4 million, respectively, charged to exploration expense.

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, 2011, the Company used three-year average historical NYMEX prices of $78.85 for crude oil and $4.12 for natural gas to estimate this liability. 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, 2011, 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 $173.7 million. This amount includes $13.7 million attributable to proved undeveloped oil and gas properties and $38.3 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2012. 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, 2011	2010
Long-term Production Participation Plan liability at January 1	$ 81,524	$ 69,433
Change in liability for accretion, vesting, changes in estimates and new Plan year activity	37,429	43,486
Cash payments accrued as compensation expense and reflected as a current payable	(38,294)	(31,395)
Long-term Production Participation Plan liability at December 31	$ 80,659	$ 81,524

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. The amount recorded is not allocated to general and administrative expense or exploration expense because the adjustment of the liability is associated with the future net cash flows from the oil and gas properties rather than current period performance. The following table presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items (in thousands):

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	Year Ended December 31,		
	2011	2010	2009
General and administrative expense	$ (770)	$ 10,676	$ 2,842
Exploration expense	(95)	1,415	425
Total	$ (865)	$ 12,091	$ 3,267

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 2011, 2010 and 2009 were $5.0 million, $3.6 million and $3.7 million, respectively. Employees vest in employer contributions at 20% per year of completed service.

8. SHAREHOLDERS' EQUITY AND NONCONTROLLING INTEREST

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

	Year Ended December 31, 2011
Balance at January 1	$ -
Contributions from noncontrolling interest	8,333
Net income (loss)	(59)
Balance at December 31	$ 8,274

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.

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. All common share and per share amounts in these consolidated financial statements and related notes for periods prior to February 2011 have been retroactively adjusted to reflect the stock split. 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.

Common Stock Offering. In February 2009, the Company completed a public offering of its common stock, selling 16,900,000 shares of common stock at a price of $14.50 per share and providing net proceeds of $234.8 million after underwriters' fees and offering expenses. The Company used the net proceeds to repay a portion of the debt outstanding under its credit agreement.

6.25% Convertible Perpetual Preferred Stock Offering—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.

Each holder of the preferred stock is 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 has been declared by Whiting’s board of directors. Each share of preferred stock has a liquidation preference of $100.00 per share plus accumulated and unpaid dividends and is convertible, at a holder’s option, into shares of Whiting’s common stock based on an conversion price of $21.70815, subject to adjustment upon the occurrence of certain events. The preferred stock is not redeemable by the Company. At any time on or after June 15, 2013, the Company may cause all outstanding shares of this preferred stock to be converted into shares of common stock if the closing price of our common stock equals or exceeds 120% of the then-prevailing conversion price for at least 20 trading days in a period of 30 consecutive trading days. The holders of preferred stock have no voting rights unless dividends payable on the preferred stock are in arrears for six or more quarterly periods.

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Induced Conversion of 6.25% Convertible Perpetual Preferred Stock. In August 2010, Whiting commenced an offer to exchange up to 3,277,500, or 95%, of its preferred stock for the following consideration per share of preferred stock: 4.6066 shares of its common stock and a cash premium of $14.50. The exchange offer expired in September 2010 and resulted in the Company accepting 3,277,500 shares of preferred stock in exchange for the issuance of 15,098,020 shares of common stock and a cash premium payment of $47.5 million. Following the exchange offer, the 3,277,500 shares of preferred stock accepted in the exchange were cancelled, and a total of 172,500 shares of preferred stock remained outstanding.

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive Plan (the "Equity Plan"), pursuant to which 2,978,323 shares of the Company's common stock have been reserved for issuance. 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, 2011, 1,571,518 shares of common stock remained available for grant under the Plan.

For the years ended December 31, 2011, 2010 and 2009, total stock compensation expense recognized for restricted share awards and stock options was $13.5 million, $8.9 million and $7.7 million, respectively.

Restricted Shares. Restricted stock awards for executive officers, directors and employees generally vest ratably over a 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 2011, January 2010 and February 2009, 201,420 shares, 180,898 shares and 419,298 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.

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:

	2011	2010	2009
Number of simulations	65,000	65,000	100,000
Expected volatility	75.8%	75.9%	70.0%
Risk-free rate	1.00%	1.40%	1.33%

The grant date fair value of the market-based restricted stock as determined by the Monte Carlo valuation model was $42.20 per share in January 2011, $22.99 per share in January 2010 and $3.46 per share in February 2009.

The following table shows a summary of the Company's nonvested restricted stock as of December 31, 2009, 2010 and 2011 as well as activity during the years then ended:

	Number of Shares	Weighted Average Grant Date Fair Value
Restricted stock awards nonvested, January 1, 2009	517,528	$ 21.21
Granted	728,452	7.83
Vested	(198,482)	21.13
Forfeited	(10,970)	17.72
Restricted stock awards nonvested, December 31, 2009	1,036,528	11.86
Granted	324,770	28.44
Vested	(465,194)	14.49
Forfeited	(26,734)	24.10
Restricted stock awards nonvested, December 31, 2010	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

As of December 31, 2011, there was $7.6 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 1.9 years. For the years ended December 31, 2011, 2010 and 2009, the total fair value of restricted stock vested was $26.0 million, $17.1 million and $2.5 million, respectively.

Stock Options. In January 2011, January 2010 and February 2009, 80,820 stock options, 55,302 stock options and 241,214 stock options, respectively, were granted under the 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. 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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	2011	2010	2009
Risk-free interest rate	2.47%	2.75%	2.0%
Expected volatility	59.3%	58.8%	58.1%
Expected term	6.0 yrs.	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 $34.15 per share in January 2011, $19.44 per share in January 2010 and $5.93 per share in February 2009.

The following table shows a summary of the Company's stock options outstanding as of December 31, 2009, 2010 and 2011 as well as activity during the years then ended (aggregate intrinsic value presented in thousands):

	Number of Options	Weighted Average Exercise Price per Share	Aggregate Intrinsic Value	Weighted Average Remaining Contractual Term (in Years)
Options outstanding at January 1, 2009	-	$ -		
Granted	241,214	12.76		
Exercised	-	-	$ -	
Forfeited or expired	-	-		
Options outstanding at December 31, 2009	241,214	12.76		
Granted	55,302	34.31		
Exercised	-	-	$ -	
Forfeited or expired	-	-		
Options outstanding at December 31, 2010	296,516	16.78		
Granted	80,820	60.28		
Exercised	-	-	$ -	
Forfeited or expired	-	-		
Options outstanding at December 31, 2011	377,336	$ 26.09	$ 7,771.9	7.7
Options vested and expected to vest at December 31, 2011	377,336	$ 26.09	$ 7,771.9	7.7
Options exercisable at December 31, 2011	179,243	$ 14.97	$ 5,685.3	7.2

Unrecognized compensation cost as of December 31, 2011 related to unvested stock option awards was $1.4 million, which is expected to be recognized over a period of 1.9 years.

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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9. INCOME TAXES

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

	Year Ended December 31,		
	2011	2010	2009
Current income tax expense (refund):			
Federal	$ 107	$ 892	$ 741
State	3,746	4,087	(505)
Total current income tax expense	3,853	4,979	236
Deferred income tax expense (benefit):			
Federal	272,653	188,386	(56,136)
State	12,185	11,425	(53)
Total deferred income tax expense (benefit)	284,838	199,811	(56,189)
Total	$ 288,691	$ 204,790	$ (55,953)

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,		
	2011	2010	2009
U.S. statutory income tax expense (benefit)	$ 273,112	$ 189,505	$ (56,992)
State income taxes, net of federal benefit	16,602	14,051	(1,228)
Statutory depletion	(697)	(632)	(394)
Enacted changes in state tax laws	(1,842)	-	711
Permanent items	1,420	1,071	1,482
Other	96	795	468
Total	$ 288,691	$ 204,790	$ (55,953)

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The principal components of the Company’s deferred income tax assets and liabilities at December 31, 2011 and 2010 were as follows (in thousands):

	Year Ended December 31, 2011	2010
Deferred income tax assets:		
Net operating loss carryforward	$ 172,531	$ 121,503
Derivative instruments	60,938	77,966
Production Participation Plan liability	29,764	30,164
Tax sharing liability	9,062	9,919
Asset retirement obligations	17,079	14,159
Underwriter fees	4,348	5,048
Restricted stock compensation	5,431	2,807
Enhanced oil recovery credit carryforwards	7,946	7,946
Alternative minimum tax credit carryforwards	11,391	11,285
Foreign tax credit carryforwards	1,230	1,230
Other	650	-
Total deferred income tax assets	320,370	282,027
Less valuation allowances	(1,230)	(1,230)
Net deferred income tax assets	319,140	280,797
Deferred income tax liabilities:		
Oil and gas properties	1,108,276	806,312
Trust distributions	36,091	18,093
Other	-	11
Total deferred income tax liabilities	1,144,367	824,416
Total net deferred income tax liabilities	$ 825,227	$ 543,619

As of December 31, 2011, we had federal net operating loss carryforwards of $503.8 million and various state net operating loss carryforwards. The determination of the state net operating loss 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 net operating loss will expire between 2027 and 2031, and the state net operating losses will expire between 2012 and 2028.

Enhanced oil recovery (“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, 2011, the Company had recognized aggregate enhanced oil recovery 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, 2011, the Company had AMT credits totaling $11.4 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, 2011, the Company’s foreign tax credit carryforwards totaled $1.2 million, which will expire between 2014 and 2016. As of December 31, 2011, 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, 2011	2010
Assets:		
Current deferred income taxes	$ -	$ -
Liabilities:		
Current deferred income taxes	1,584	4,548
Non-current deferred income taxes	823,643	539,071
Net deferred income tax liabilities	$ 825,227	$ 543,619

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

	Year Ended December 31, 2011	2010	2009
Beginning balance at January 1	$ 299	$ 299	$ 299
Increases related to tax position taken in the current year	-	-	-
Ending balance at December 31	$ 299	$ 299	$ 299

Included in the unrecognized tax benefit balance at December 31, 2011, are $0.3 million of tax positions, the allowance of which would positively affect the annual effective income tax rate. For the year ended December 31, 2011, 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, in various states, and previously filed in two foreign jurisdictions each with varying statutes of limitations. The 2008 through 2011 tax years generally remain subject to examination by federal and state tax authorities. The foreign jurisdictions generally remain subject to examination by their respective authorities for 2005 and 2006.

10. 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, 2011	2010	2009
Basic Earnings Per Share (1)			
Numerator:			
Net income (loss) available to shareholders	$ 491,687	$ 336,653	$ (106,882)
Preferred stock dividends (2)	(1,077)	(63,069)	(11,247)
Net income (loss) available to common shareholders, basic	$ 490,610	$ 273,584	$ (118,129)
Denominator:			
Weighted average shares outstanding, basic	117,345	106,338	100,088
Diluted Earnings Per Share(1)			
Numerator:			

Net income (loss) available to common shareholders, basic	$ 490,610	$ 273,584	$ (118,129)
Preferred stock dividends	1,077	1,078	-
Adjusted net income (loss) available to common shareholders, diluted	$ 491,687	$ 274,662	$ (118,129)
Denominator:			
Weighted average shares outstanding, basic	117,345	106,338	100,088
Restricted stock and stock options	529	714	-
Convertible perpetual preferred stock	794	794	-
Weighted average shares outstanding, diluted	118,668	107,846	100,088
Earnings (loss) per common share, basic	$ 4.18	$ 2.57	$ (1.18)
Earnings (loss) per common share, diluted	$ 4.14	$ 2.55	$ (1.18)

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(1) All share and per share amounts have been retroactively restated for the 2009 and 2010 periods to reflect the Company's February 2011 two-for-one stock split described in Note 8 to these consolidated financial statements.

(2) For the years ended December 31, 2010 and 2009, amounts include a decrease of $0.9 million in preferred stock dividends for preferred stock dividends accumulated. There was no accumulated dividend adjustment for the year ended December 31, 2011.

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For the year ended December 31, 2011, the diluted earnings per share calculation excludes the effect of 2,285 common shares for stock options that were out-of-the-money and 113,228 incremental common shares for restricted stock that did not meet its market-based vesting criteria as of December 31, 2011. For the year ended December 31, 2010, the diluted earnings per share calculation excludes the effect of 10,713,390 incremental common shares (which were issuable upon the conversion of perpetual preferred stock as of a January 1, 2010 assumed conversion date) because their effect was anti-dilutive. For the year ended December 31, 2009, the Company had a net loss. Therefore, the diluted earnings per share calculation for that period excludes the effect of 697,458 shares of restricted stock and stock options, as well as 8,316,427 common shares, which were issuable upon the assumed conversion of perpetual preferred stock, because their effect was anti-dilutive.

11. 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, the Trust is a related party of the Company. The following table summarizes the related party receivable and payable balances between the Company and the Trust as of December 31, 2011 and 2010 (in thousands):

	December 31,	
	2011	2010
Assets		
Unit distributions due from Trust (1)	$ 1,127	$ 1,067
Total	$ 1,127	$ 1,067
Liabilities		
Unit distributions payable to Trust (2)	$ 7,146	$ 6,769
Current portion of derivative liability due to Trust	4,336	3,208
Non-current derivative liability due to Trust	-	3,003
Total	$ 11,482	$ 12,980

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(1) This amount represents Whiting's 15.8% interest in the net proceeds due from the Trust and is included within accounts receivable trade, net in the Company's consolidated balance sheets.
(2) This amount represents net proceeds from the Trust's underlying properties as well as realized cash settlements on Trust derivatives, that the Company has received between the last Trust distribution date and December 31, 2011, but which the Company has not yet distributed to the Trust as of December 31, 2011. Due to ongoing processing of Trust revenues and expenses after December 31, 2011, the amount of Whiting's next scheduled distribution to the Trust, and the related distribution by the Trust to its unitholders, will differ from this amount. This amount is included within accounts payable trade in the Company's consolidated balance sheet.

For the year ended December 31, 2011, Whiting paid $41.6 million, net of state tax withholdings, in unit distributions to the Trust and received $6.5 million in distributions back from the Trust pursuant to its retained ownership in 2,186,389 Trust units.

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 future tax benefits the Company realizes annually as a result of this step-up in tax bases. In 2014, Whiting will be obligated to pay Alliant the present value of 90% of the remaining tax benefits expected to result from its increased tax bases, assuming all such tax benefits will be realized in future years.

The present value of estimated payments due Alliant Energy under this agreement have been reflected in the Company's consolidated balance sheets. The long-term portions of this tax sharing liability of $21.2 million and $20.7 million as of December 31, 2011 and 2010, respectively, have been included in other long-term liabilities, and the Company's estimated payment of $1.5 million to be made in 2012 is reflected as a current liability at December 31, 2011. During 2011, 2010 and 2009, the Company made payments of $1.9 million, $1.6 million and $2.7 million, respectively, under this agreement and recognized interest expense of $2.1 million, $1.5 million and $1.6 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.

12. COMMITMENTS AND CONTINGENCIES

Non-cancelable Leases—The Company leases 135,026 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, 46,700 square feet of office space in Midland, Texas expiring in 2012, and 20,000 square feet of office space in Dickinson, North Dakota expiring in 2016. Rental expense for 2011, 2010 and 2009 amounted to $4.4 million, $3.4 million and $3.0 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2011 are as follows (in thousands):

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2012	$3,959
2013	3,306
2014	336
2015	336
2016	224
Total	$8,161

Purchase Contracts—The Company has four take-or-pay purchase agreements, two agreements 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 CO_2 for use in its enhanced recovery projects in the Postle field in Oklahoma and the North Ward Estes field in Texas. The purchase agreements are with three different suppliers. Under the terms of the agreements, the Company is obligated to purchase a minimum daily volume of CO_2 (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 two ship-or-pay agreements with two different parties, one expiring in June 2013 and one expiring in December 2017, whereby it has committed to transport a minimum daily volume of CO_2 via certain pipelines or else pay for any deficiencies at a price stipulated in the contract. The CO_2 volumes planned for use in the Company's enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes specified in these agreements. Therefore, the Company expects to avoid any payments for deficiencies. As of December 31, 2011, future commitments under these purchase agreements amounted to $783.2 million through 2029.

Drilling Contracts—The Company currently has 14 drilling rigs under long-term contract, of which three drilling rigs expire in 2012, two in 2013, six in 2014 and three in 2015. All of these rigs are operating in the Rocky Mountains region. As of December 31, 2011, early termination of the remaining contracts would require termination penalties of $205.8 million, which would be in lieu of paying the remaining drilling commitments of $270.9 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.

Litigation—The Company is subject to litigation, claims and governmental and regulatory proceedings arising in the ordinary course of business. It is the opinion of the Company's management that all claims and litigation involving the Company are not likely to have a material effect on its consolidated financial position, cash flows or results of operations.

13. SUBSEQUENT EVENTS

The Company has evaluated subsequent events through the date that these financial statements were issued, and has identified the following:

Whiting USA Trust II. In January 2012, Whiting filed an amendment to its initial registration statement relating to a proposed initial public offering of units of beneficial interest in Whiting USA Trust II. Whiting plans to contribute a term net profits interest in certain of its oil and natural gas properties in exchange for trust units, and Whiting will in turn then offer such trust units to the public. These property interests had estimated reserves of up to 18.3 MMBOE, as of a January 1, 2012 effective date, representing up to 5% of the Company's proved reserves as of December 31, 2011, and 7%, or 4.9 MBOE/d, of the Company's December 2011 average daily net production. Whiting intends to use the net proceeds from this offering to repay a portion of the debt outstanding under its credit agreement. The amount of proceeds ultimately received from this offering, and the timing of the completion of this offering, is subject to a variety of factors, including favorable market conditions. Whiting cannot provide any assurance, however, that it will be able to complete this offering or any other form of asset sales.

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Preferred stock dividend. On February 15, 2012, the Company declared a dividend of $1.5625 per share on its 6.25% convertible perpetual preferred stock. The total dividend amounting to $0.3 million is payable on March 15, 2012 to holders of record on March 1, 2012.

14. OIL AND GAS ACTIVITIES

The Company's oil and gas activities for 2011, 2010 and 2009 were entirely within the United States. Costs incurred in oil and gas producing activities were as follows (in thousands):

	Year Ended December 31,		
	2011	2010	2009
Development	$ 1,245,150	$ 723,687	$ 436,721
Proved property acquisition	4,324	22,763	78,800
Unproved property acquisition	191,482	155,472	12,872
Exploration	400,823	114,012	50,970
Total	$ 1,841,779	$ 1,015,934	$ 579,363

During 2011, 2010 and 2009, additions to oil and gas properties of $4.9 million, $3.5 million and $0.5 million were recorded for the estimated costs of future abandonment related to new wells drilled or acquired.

Net capitalized costs related to the Company's oil and gas producing activities were as follows (in thousands):

	Year Ended December 31,	
	2011	2010
Proved oil and gas properties	$ 7,221,550	$ 5,661,619
Unproved oil and gas properties	354,774	226,336
Accumulated depreciation, depletion and amortization	(2,066,830)	(1,612,553)
Oil and gas properties, net	$ 5,509,494	$ 4,275,402

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,		
	2011	2010	2009
Beginning balance at January 1	$ 4,434	$ -	$ -
Additions to capitalized exploratory well costs pending the determination of proved reserves	354,962	81,167	4,095
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(267,847)	(76,733)	(4,095)
Capitalized exploratory well costs charged to expense	(1,030)	-	-
Ending balance at December 31	$ 90,519	$ 4,434	$ -

At December 31, 2011, the Company had no costs capitalized for exploratory wells in progress for a period of greater than one year after the completion of drilling.

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, 2011. Proved reserve estimates included herein conform to the definitions prescribed by the U.S. Securities and Exchange Commission. The 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, 2011, 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, 2009, 2010 and 2011 are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Balance—January 1, 2009	180,008	354,779	239,138
Extensions and discoveries	25,115	41,969	32,109
Sales of minerals in place	(2,689)	(1,559)	(2,949)
Purchases of minerals in place	3,177	4,155	3,870
Production	(15,381)	(29,333)	(20,269)
Revisions to previous estimates	33,566	(62,618)	23,130
Balance—December 31, 2009	223,796	307,393	275,029
Extensions and discoveries	29,434	23,135	33,290
Sales of minerals in place	(225)	(500)	(308)
Purchases of minerals in place	505	1,526	759
Production	(19,031)	(27,392)	(23,596)
Revisions to previous estimates	19,799	(618)	19,695
Balance—December 31, 2010	254,278	303,544	304,869
Extensions and discoveries	44,684	23,211	48,552
Sales of minerals in place	(1,211)	(9,759)	(2,837)
Purchases of minerals in place	172	1,639	445
Production	(20,373)	(26,443)	(24,780)
Revisions to previous estimates	20,203	(7,217)	19,000
Balance—December 31, 2011	297,753	284,975	345,249
Proved developed reserves:			
December 31, 2008	120,961	229,224	159,165
December 31, 2009	144,813	178,782	174,610
December 31, 2010	178,409	220,530	215,164
December 31, 2011	203,084	211,297	238,300
Proved undeveloped reserves:			
December 31, 2008	59,047	125,555	79,973
December 31, 2009	78,983	128,611	100,419
December 31, 2010	75,869	83,014	89,705
December 31, 2011	94,669	73,678	106,949

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

- 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 liquids component of the net 14.3 MMBOE revision consisted of a 15.7 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 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.

- Extensions and discoveries. In 2011, total extensions and discoveries of 48.6 MMBOE were primarily attributable to successful drilling in the Sanish field and Pronghorn area of the Lewis & Clark prospect. 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.

Notable changes in proved reserves for the year ended December 31, 2010 included:

- Revisions to previous estimates. In 2010, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 19.7 MMBOE. Included in these revisions were (i) 15.4 MMBOE of upward adjustments caused by higher crude oil and natural gas prices incorporated into the Company's reserve estimates at December 31, 2010 as compared to December 31, 2009, and (ii) 4.3 MMBOE of net upward adjustments attributable to reservoir analysis and well performance. The liquids component of the net 4.3 MMBOE revision consisted of a 7.4 MMBOE increase that was primarily related to the Sanish field, where reserve assignments for proved developed producing as well as proved undeveloped well locations were adjusted upward to reflect the current performance of producing wells. The gas component of the net 4.3 MMBOE revision consisted of a 3.1 MMBOE decrease that was primarily related to the Beall East field, where three proved undeveloped locations were removed from our proved reserve estimate since those wells are no longer planned to be drilled due to low gas prices.

- Extensions and discoveries. In 2010, total extensions and discoveries of 33.3 MMBOE were primarily attributable to successful drilling in the Sanish field and related proved undeveloped well locations added during the year, which in turn increased the Company's proved reserves in the Sanish area.

Notable changes in proved reserves for the year ended December 31, 2009 included:

- Revisions to previous estimates. In 2009, revisions to previous estimates increased proved developed and undeveloped reserves by a net amount of 23.1 MMBOE. Included in these revisions were (i) 17.3 MMBOE of net upward adjustments caused by higher crude oil prices incorporated into the Company's reserve estimates at December 31, 2009 as compared to December 31, 2008 that were partially offset by lower natural gas prices as of December 31, 2009, and (ii) 5.8 MMBOE of net upward adjustments attributable to reservoir analysis and well performance. The liquids component of the 5.8 MMBOE revision consisted of a 14.8 MMBOE increase that was primarily related to North Ward Estes, where additional field areas are now planned for CO2 injection and where the total amount of CO2 planned for injection into previously identified flood pattern areas has been increased. The gas component of the 5.8 MMBOE revision consisted of a 9.0 MMBOE decrease that was primarily related to the Sulphur Creek field, where reserve assignments for proved developed producing as well as proved undeveloped well locations were adjusted downward to reflect the current performance of producing wells.

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- Extensions and discoveries. In 2009, total extensions and discoveries of 32.1 MMBOE were primarily attributable to successful drilling in the Sanish and Parshall fields and related proved undeveloped well locations added during the year, which in turn extended the proved acreage in those areas.

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 ("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 2%–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, 2011, 2010 and 2009 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, 2011, 2010 and 2009, 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, 2011	December 31, 2010	December 31, 2009
Future cash flows	$ 26,815,086	$ 19,314,032	$ 13,077,148
Future production costs	(8,908,131)	(7,705,465)	(5,668,889)
Future development costs	(1,982,813)	(1,491,937)	(1,405,734)
Future income tax expense	(4,875,973)	(2,890,668)	(1,292,719)
Future net cash flows	11,048,169	7,225,962	4,709,806
10% annual discount for estimated timing of cash flows	(5,775,677)	(3,558,356)	(2,366,264)
Standardized measure of discounted future net cash flows	$ 5,272,492	$ 3,667,606	$ 2,343,542

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 have decreased by $50.7 million in 2011, decreased by $12.6 million in 2010 and increased by $24.6 million in 2009.

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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, 2011	December 31, 2010	December 31, 2009
Beginning of year	$ 3,667,606	$ 2,343,542	$ 1,376,448
Sale of oil and gas produced, net of production costs	(1,415,469)	(1,103,060)	(615,597)
Sales of minerals in place	(67,600)	(5,927)	(40,673)
Net changes in prices and production costs	2,246,014	1,881,636	1,233,813
Extensions, discoveries and improved recoveries	1,156,740	639,924	442,879
Previously estimated development costs incurred during the period	408,079	405,499	260,350
Changes in estimated future development costs	(797,542)	(434,549)	(452,480)
Purchases of mineral in place	10,604	14,597	53,372
Revisions of previous quantity estimates	452,668	378,552	319,028
Net change in income taxes	(755,369)	(686,962)	(371,243)
Accretion of discount	366,761	234,354	137,645
End of year	$ 5,272,492	$ 3,667,606	$ 2,343,542

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, 2011, 2010 and 2009 as follows:

	2011	2010	2009
Oil (per Bbl)	$ 85.86	$ 70.32	$ 52.19
Natural Gas (per Mcf)	$ 4.39	$ 4.72	$ 3.77

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16. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2011 and 2010 (in thousands, except per share data):

	Three Months Ended			
	March 31, 2011	June 30, 2011	September 30, 2011	December 31, 2011
Year ended December 31, 2011:				
Oil and natural gas sales	$ 425,683	$ 473,865	$ 468,573	$ 492,025
Operating profit (loss) (1)	214,789	255,572	233,543	243,362
Net income (loss)	19,144	202,880	205,966	62,620
Basic earnings (loss) per share(2)	0.16	1.73	1.75	0.54
Diluted earnings (loss) per share(2)	0.16	1.71	1.74	0.53

	Three Months Ended			
	March 31, 2010	June 30, 2010	September 30, 2010	December 31, 2010
Year ended December 31, 2010:				
Oil and natural gas sales	$ 340,694	$ 363,028	$ 365,239	$ 406,327
Operating profit (loss) (1)	157,192	174,665	172,341	204,965
Net income (loss)	81,220	119,926	5,612	65,925
Basic earnings (loss) per share(2)	0.80	1.18	0.06	0.56
Diluted earnings (loss) per share(2)	0.73	1.06	0.06	0.56

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

(2) All per share amounts have been retroactively restated for the 2010 periods to reflect the Company's two-for-one stock split in February 2011, as described in Note 8 to these consolidated financial statements.

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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, 2011. 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, 2011 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 report of management required under this Item 9A is contained in Item 8 of this Annual Report on Form 10-K under the caption "Management's Annual Report on Internal Control Over Financial Reporting".

Attestation Report of Registered Public Accounting Firm. The attestation report required under this Item 9A is contained in Item 8 of this Annual Report on Form 10-K under the caption "Report of Independent Registered Public Accounting Firm".

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, 2011 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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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 2012 Annual Meeting of Stockholders (the "Proxy Statement") is hereby 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 hereby 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 hereby incorporated 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, 2011.

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 (reduced by securities reflected in the first column)
Equity compensation plans approved by security holders(1)	377,336	$ 26.09	1,571,518 (2)
Equity compensation plans not approved by security holders	-	N/A	-

Total	377,336	$ 26.09	1,571,518	(2)

(1) Includes only the Whiting Petroleum Corporation 2003 Equity Incentive Plan.

(2) Number of securities reduced by 724,395 shares of restricted common stock previously issued for which the restrictions have not lapsed.

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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 hereby incorporated 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 hereby incorporated by reference.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) 1. Financial statements – The following financial statements and the report of independent registered public accounting firm are contained in Item 8.

a. Report of Independent Registered Public Accounting Firm

b. Consolidated Balance Sheets as of December 31, 2011 and 2010

c. Consolidated Statements of Income for the Years Ended December 31, 2011, 2010 and 2009

d. Consolidated Statements of Cash Flows for the Years Ended December 31, 2011, 2010 and 2009

e. Consolidated Statements of Equity and Comprehensive Income for the Years Ended December 31, 2011, 2010 and 2009

f. Notes to Consolidated Financial Statements

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, 2011	December 31, 2010
ASSETS		
Current assets	$1,986	$1,838
Investment in subsidiaries	1,910,944	1,416,880
Intercompany receivable	1,733,629	1,732,681
Total assets	$3,646,559	$3,151,399
LIABILITIES AND EQUITY		
Current liabilities	$4,482	$4,847
Long-term debt	600,000	600,000
Other long-term liabilities	21,460	21,006
Shareholders' equity	3,020,617	2,525,546
Total liabilities and equity	$3,646,559	$3,151,399

CONDENSED STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31, 2011	2010	2009
Operating expenses:			
General and administrative	$(12,024)	$(7,835)	$(6,659)
Interest expense	(2,066)	(1,844)	(2,139)
Equity in earnings (losses) of subsidiaries	500,564	342,671	(101,107)
Income (loss) before income taxes	486,474	332,992	(109,905)
Income tax benefit	5,213	3,661	3,023
Net income (loss)	$491,687	$336,653	$(106,882)

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,		
	2011	2010	2009
Cash flows provided by operating activities	$4,962	$1,108	$2,961
Cash flows from investing activities:			
Investment in subsidiaries	-	-	-
Cash flows from financing activities:			
Intercompany receivable	(3,091)	507	(260)
Other financing activities	(1,871)	(1,615)	(2,701)
Net cash used in financing activities	(4,962)	(1,108)	(2,961)
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	$(6,500)	$(5,937)	$(5,766)

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, 2011	2010	2009
NONCASH FINANCING ACTIVITIES:			
Issuance of preferred stock increasing shareholders' equity	$-	$-	$ 334,112
Issuance of preferred stock increasing intercompany receivable	$-	$-	$ 334,112
Issuance of common stock increasing shareholders' equity	$-	$-	$ 234,753
Issuance of common stock increasing intercompany receivable	$-	$-	$ 234,753
Issuance of 6.50% Senior Subordinated Notes due 2018 increasing long-term debt	$-	$350,000	$ -
Issuance of 6.50% Senior Subordinated Notes due 2018 increasing intercompany receivable	$-	$350,000	$ -
Redemption of 7.25% Senior Subordinated Notes due 2012 decreasing long-term debt	$-	$(150,000)	$ -
Redemption of 7.25% Senior Subordinated Notes due 2012 decreasing intercompany receivable	$-	$(150,000)	$ -
Redemption of 7.25% Senior Subordinated Notes due 2013 decreasing long-term debt	$-	$(223,988)	$ -
Redemption of 7.25% Senior Subordinated Notes due 2013 decreasing intercompany receivable	$-	$(223,988)	$ -
Issuance of common stock related to the induced conversion of preferred stock increasing shareholders' equity	$-	$317,406	$ -
Issuance of common stock related to the induced conversion of preferred stock increasing intercompany receivable	$-	$317,406	$ -
Preferred stock cancelled in connection with its induced conversion decreasing shareholders' equity	$-	$(317,406)	$ -
Preferred stock cancelled in connection with its induced conversion decreasing intercompany receivable	$-	$(317,406)	$ -
Preferred stock dividends paid decreasing shareholders' equity	$(1,077)	$(16,441)	$ (10,302)
Preferred stock dividends paid decreasing intercompany receivable	$(1,077)	$(16,441)	$ (10,302)
Premium on induced conversion of 6.25% convertible perpetual preferred stock decreasing shareholders' equity	$-	$(47,529)	$ -
Premium on induced conversion of 6.25% convertible perpetual preferred stock decreasing intercompany receivable	$-	$(47,529)	$ -
Distributions from Whiting USA Trust I increasing intercompany receivable	$6,500	$5,937	$ 5,766

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 the payment of dividends on the 6.25% convertible perpetual preferred stock, 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, 2011, total restricted net assets were $2,801.3 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, 2011 and 2010 (in thousands):

	December 31, 2011	December 31, 2010
Long-term debt:		
6.5% Senior Subordinated Notes due 2018	$ 350,000	$ 350,000
7% Senior Subordinated Notes due 2014	250,000	250,000
Other long-term liabilities:		
Tax sharing liability	21,161	20,707
Other	299	299