WHITING PETROLEUM CORP
Form 10-K
February 24, 2011

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, 2010

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:

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
(Title of Class)	(Name of each exchange on which registered)

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

Indicate by check mark if the Registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.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 T No £

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. 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, 2010: $4,012,157,212.

Number of shares of the registrant's common stock outstanding at February 22, 2011: 118,115,582 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2011 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.

"Bcfe" One billion cubic feet of natural gas equivalent.

"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.

"farmout" An assignment of an interest in a drilling location and related acreage conditioned upon the drilling of a well on that location.

"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.

"MBOE" One thousand BOE.

"MBOE/d" One MBOE per day.

"Mcf" One thousand cubic feet of natural gas.

"Mcfe" One thousand cubic feet of natural gas equivalent.

"MMBbl" One million Bbl.

“MMBOE” One million BOE.

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"MMBtu" One million British Thermal Units.

"MMcf" One million cubic feet of natural gas.

"MMcf/d" One MMcf per day.

"MMcfe/d" One MMcfe per day.

"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 price and costs as of the date of estimation without future escalation, 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.

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

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

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

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

"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.

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“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 Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan 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, 2010, our estimated proved reserves totaled 304.9 MMBOE, representing an 11% increase in our proved reserves since December 31, 2009. Our 2010 average daily production was 64.6 MBOE/d and implies an average reserve life of approximately 12.9 years.

The following table summarizes by core area, our estimated proved reserves as of December 31, 2010, their corresponding pre-tax PV10% values, and our December 2010 average daily production rates, as well as our company's total standardized measure of discounted future net cash flows as of December 31, 2010:

	Proved Reserves (1)					
Core Area	Oil (2) (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil (2)	Pre-Tax PV10% Value (3) (In millions)	4th Quarter 2010 Average Daily Production (MBOE/d)
Permian Basin	115.6	47.9	123.6	94 %	$ 1,471.5	12.2
Rocky Mountains	94.5	162.8	121.6	78 %	2,425.5	40.8
Mid-Continent	38.2	19.9	41.5	92 %	955.2	9.3
Gulf Coast	3.2	36.9	9.4	34 %	113.3	2.7
Michigan	2.8	36.0	8.8	32 %	78.9	2.9
Total	254.3	303.5	304.9	83 %	$ 5,044.4	67.9
Discounted Future Income Taxes	-	-	-	-	(1,376.8)	-
Standardized Measure of Discounted Future Net Cash Flows	-	-	-	-	$ 3,667.6	-

(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, 2010, 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.

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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.

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 2010, we incurred $1,007.6 million in exploration, development and total acquisition expenditures, including $822.9 million for the drilling of 189 gross (88.0 net) wells. Of these new wells, 84.3 (net) resulted in productive completions and 3.7 (net) were unsuccessful, yielding a 96% success rate.

Our current 2011 capital budget is $1,350.0 million, and included in this amount is approximately $110.0 million in acreage acquisition costs. Previously, we have not included acreage acquisition costs in our annual capital budgets. However, during 2010 we incurred $155.5 million in aggregate acreage purchases and have therefore decided to include such costs in our capital budgets going forward. The 2011 capital budget of $1,350.0 million represents a 38% increase from the $978.3 million in exploration, development and acreage expenditures we incurred in 2010. We expect to fund substantially all of our 2011 capital budget using net cash provided by operating activities, which has increased primarily in response to the higher oil prices experienced throughout 2010 and continuing into the first part of 2011, 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.

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 unadjusted purchase price was $19.2 million, and substantially all of it was allocated to the properties and acreage acquired.

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.

2009 Acquisitions. During 2009, we 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.

We completed the first acquisition of additional royalty and overriding royalty interests in November 2009, with a purchase price of $38.7 million and an effective date of October 1, 2009. The average daily net production attributable to this transaction was approximately 0.3 MBOE/d in September 2009. Estimated proved reserves attributable to the acquired interests are 2.2 MMBOE, resulting in an acquisition price of $17.59 per BOE. We completed the second acquisition of additional royalty and overriding royalty interests in December 2009, with a purchase price of $27.4 million and an effective date of November 1, 2009. The average daily net production attributable to this transaction was approximately 0.2 MBOE/d in September 2009. Estimated proved reserves attributable to the acquired interests are 1.6 MMBOE, resulting in an acquisition price of $17.13 per BOE. Reserves attributable to royalty and overriding royalty interests are not burdened by operating expenses or any additional capital costs, including CO_2 costs, which are paid by the working interest owners.

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In aggregate, the two acquisitions in the North Ward Estes field represent 3.8 MMBOE of proved reserves at an acquisition price of $66.1 million, or $17.39 per BOE. 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, we 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 our net drilling and well completion costs to receive 50% of our working interest and net revenue interest in the first and second wells planned for each of the units. Pursuant to the agreement, we will remain the operator for each unit.

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

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 and Denver Julesburg Basin (“DJ Basin”) projects has become one of our central objectives. As of December 31, 2010, we have assembled approximately 109,200 gross (66,500 net) acres on the eastern side of the Williston Basin in North Dakota in an active oil development play at our Sanish field area, where the Middle Bakken reservoir is oil productive. As of February 15, 2011, we have participated in the drilling of 229 successful wells (172 operated) in our Sanish field acreage that had a combined net production rate of 22.3 MBOE/d during December 2010.

As of December 31, 2010, we have assembled approximately 360,500 gross (234,900 net) acres in the Lewis & Clark Prospect in Billings, Golden Valley and Stark Counties, North Dakota. Through the end of 2010 we have drilled seven horizontal wells into the Three Forks reservoir at Lewis & Clark, and the average production from these seven wells was approximately 0.6 MBOE/d during the first 30 days of production. We hold a working interest in 250 1,280-acre spacing units in the Lewis & Clark Prospect, and we estimate two to four wells per 1,280-acre spacing unit to fully develop this area. We currently have five drilling rigs operating in this project, and we plan to double this rig count by the end of 2011.

In addition to the Lewis & Clark Prospect, we have assembled acreage positions in the Cassandra, Hidden Bench and Big Island prospects located in North Dakota, and the Starbuck Prospect, located in Montana. In aggregate we have assembled approximately 289,600 gross (206,100 net) acres. In 2011 we intend to test each area with one or more wells.

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In May 2008 we acquired interests in the Flat Rock Gas field in Uintah County, Utah. The main production in the Flat Rock field is from the Entrada formation. In late 2009 and early 2010, we entered into 5-year fixed-price gas contracts that averaged over $5.15 per Mcf at our Flat Rock field to maintain the economic viability of this production. During 2010, we drilled four wells in our Flat Rock field.

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 at our Redtail Prospect in Weld County, Colorado, which brings our total acreage position in that area to approximately 89,400 gross (66,100 net) acres. Drilling in this area will target the Niobrara formation. We initiated a seven well exploratory drilling program in late 2010 that will continue through June 2011, and we have drilled four wells as of February 15, 2011. Based on our current acreage position and a successful exploratory program, we could operate up to 220 wells and participate in an additional 125 non-operated wells. Initial flow rates from the Niobrara formation in the DJ Basin recently announced by other operators are ranging from 600 to 1,600 Bbls of oil per day from multi-stage fracture stimulated horizontal wells. As of December 31, 2010, we have leased over 78,800 gross (66,200 net) acres in our Big Tex Prospect in the Delaware Basin of West Texas, where we will be targeting the Wolfcamp and Bone Springs formations. Production from these two areas will be primarily oil.

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, 2010, 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 seven years. In these fields, we are actively injecting water and CO2 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 2010, 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.

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.

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Balanced, Long-Lived Asset Base. As of December 31, 2010, we had interests in 9,698 gross (3,755 net) productive wells across approximately 1,115,000 gross (560,800 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 12.9 years based on year-end 2010 proved reserves and 2010 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 30 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 6,560 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 13 professionals averaging over 22 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 June 2009, we implemented a "Drill Well on Paper" ("DWOP") process on our drilling program in the Sanish field in North Dakota. DWOP is an optimization program for all parties involved in the drilling process to engage in looking for ways to reduce the time and costs associated with the drilling of a well. The first step in the DWOP process is to determine the "technical limit" time, which is the time necessary to drill the perfect well. We then perform a step-by-step analysis of the drilling process with the ultimate goal of drilling a well within the technical limit time. The program has been very successful in the Sanish field where all of our operated rigs have been through the program. In 2009, we reduced drilling time by 10 days per well, from 38 days to 28 days. In 2010, we experienced continued success and were able to reduce the drilling time by an additional 8 days. We plan to expand this program to all of our operated rigs in North Dakota in 2011.

In 2010, we were the first to implement a 24-stage fracture stimulation treatment utilizing sliding sleeve technology and have recently run the equipment to pump a 30-stage sliding sleeve stimulation. On March 1, 2010, we completed the installation of 298 permanent geophones across the Sanish field which has allowed us to gather microseismic data on every fracture stimulation we have pumped in the field. This information has been useful in determining the effectiveness of our hydraulic stimulations along with assisting in developing the proper spacing of wellbores in the field.

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Proved, Probable and Possible Reserves

Our estimated proved, probable and possible reserves as of December 31, 2010 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.

Permian Basin:	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved		Estimated Future Capital Expenditures (In millions)
PDP	42.0	28.4	46.7	38	%	
PDNP	28.6	5.9	29.6	24	%	
PUD	45.0	13.6	47.3	38	%	
Total Proved	115.6	47.9	123.6	100	%	$814.5
Total Probable	39.9	53.3	48.7			$724.3
Total Possible	109.8	13.9	112.2			$836.2
Rocky Mountains:						
PDP	68.8	110.0	87.1	72	%	
PDNP	0.4	2.3	0.8	1	%	
PUD	25.3	50.5	33.7	27	%	
Total Proved	94.5	162.8	121.6	100	%	$492.5
Total Probable	14.2	129.8	35.8			$480.8
Total Possible	68.9	152.9	94.4			$1,079.6
Mid-Continent:						
PDP	33.5	19.0	36.6	88	%	
PDNP	0.6	0.6	0.7	2	%	
PUD	4.1	0.3	4.2	10	%	
Total Proved	38.2	19.9	41.5	100	%	$113.6
Total Probable	7.0	2.4	7.4			$209.4
Total Possible	-	-	-			$-
Gulf Coast:						
PDP	2.2	19.4	5.5	59	%	
PDNP	0.1	3.1	0.6	6	%	
PUD	0.9	14.4	3.3	35	%	
Total Proved	3.2	36.9	9.4	100	%	$49.6
Total Probable	1.8	21.9	5.5			$59.5
Total Possible	3.6	28.5	8.3			$94.3
Michigan:						
PDP	1.3	27.4	6.0	68	%	
PDNP	0.9	4.4	1.6	18	%	
PUD	0.6	4.2	1.2	14	%	
Total Proved	2.8	36.0	8.8	100	%	$21.7
Total Probable	1.8	4.8	2.7			$26.3
Total Possible	0.7	9.5	2.2			$25.6

Total Company:						
PDP	147.8	204.2	181.9	60	%	
PDNP	30.6	16.3	33.3	11	%	
PUD	75.9	83.0	89.7	29	%	
Total Proved	254.3	303.5	304.9	100	%	$1,491.9
Total Probable	64.7	212.2	100.1			$1,500.3
Total Possible	183.0	204.8	217.1			$2,035.7

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.

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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 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. During 2008, sales to Plains Marketing LP and Valero Energy Corporation accounted for 15% and 14%, 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.

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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.

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.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. 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.

Pipeline safety is regulated at both state and federal levels. 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 mandatory five-year review has revised the methodology for this index to now be based on Producer Price Index for Finished Goods (the "PPI-FG"), plus a 1.3% adjustment, for the period July 1, 2006 through July 2011. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

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Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to 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 Minerals Management Service ("MMS"). Currently, only 0.2% of our total production volumes are produced from offshore leases. However, the present value of our future abandonment obligations associated with offshore properties was $30.7 million as of December 31, 2010. Whiting is therefore required to comply with the regulations and orders issued by MMS under the Outer Continental Shelf Lands Act. Among other things, we are required to obtain prior MMS approval for any exploration plans we pursue and approval for our lease development and production plans. MMS 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, MMS could require us to suspend or terminate our operations on a federal lease.

MMS 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 MMS and the state regulatory authorities is generally applicable to all federal and state oil and gas lessees. Accordingly, we believe that the impact of royalty regulation on our operations should generally be the same as the impact on our competitors.

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

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.

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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, and 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.

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.

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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 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 or permittee of the area in which an offshore facility is located. The OPA establishes a liability limit for onshore facilities of $350.0 million, while the liability limit for offshore facilities is the payment of all removal costs plus up to $75.0 million in other damages, but these limits may not apply if a spill is caused by a party’s gross negligence or willful misconduct; the spill resulted from violation of a federal safety, construction or operating regulation; or if a party fails to report a spill or to cooperate fully in a cleanup. The 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 ($10.0 million if the offshore facility is located landward of the seaward boundary of a state) to cover liabilities related to an oil spill for which such person is statutorily responsible. The amount of financial responsibility required under OPA may be increased 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, civil or criminal enforcement actions. 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, these exploration and production wastes may be regulated by state agencies as solid waste. In addition, 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.

Clean Water Act. The Federal Water Pollution Control Act of 1972, or the Clean Water Act (the “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. The 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 the 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. The CWA and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil and other pollutants and impose liability on parties responsible for those discharges, for the costs of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. 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. The SPCC regulations were revised in 2002 and required the amendment of SPCC plans and the modification of spill control devices at many facilities. Since 2002 there have been numerous amendments and extensions for compliance with the 2002 rule and subsequent amendments. On October 7, 2010 the EPA extended the compliance date to November 10, 2011 for all facilities except drilling, production or workover facilities that are offshore, or have an offshore component, and for onshore facilities required to have and submit a facility response plan.

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Clean Air Act. The Clean Air Act restricts the emission of air pollutants from many sources, including oil and gas operations. New facilities may be required to obtain permits before construction can begin, and existing facilities may be required to obtain additional permits and incur capital costs in order to remain in compliance. More stringent regulations governing emissions of toxic air pollutants and greenhouse gases have been developed by the EPA and may increase the costs of compliance for some facilities. We believe that we are in substantial compliance with all applicable air emissions regulations.

Global Warming and Climate Control. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" ("GHGs"), including carbon dioxide and methane, may be contributing to warming of the earth's atmosphere. On April 2, 2007, in Massachusetts, et al. v. EPA, the U.S. Supreme Court required the EPA to reconsider whether GHGs cause or contribute to the endangerment of public health and the environment. As a result, on December 7, 2009, the EPA made Endangerment and Cause or Contribute findings for GHGs under its authority delegated by the Clean Air Act. Based upon these findings, the EPA has begun to regulate GHG emissions from mobile sources (e.g., cars and trucks). In addition, the EPA has promulgated regulations concerning the inventory of and regulation of GHGs from stationary sources which include many of our facilities. Further, many states have taken legal measures to reduce emission of these gases, primarily through the planned development of GHG emission inventories, permitting programs and/or regional GHG cap and trade programs. New legislation or regulatory programs that restrict emissions of or require inventory of GHGs in areas where we operate have adversely affected or will adversely affect our operations by increasing costs. The cost increases so far have resulted from costs associated with inventorying our GHG emissions, and further costs may result from the potential new requirements to obtain GHG emissions permits, install additional emission control equipment and an increased monitoring and record-keeping burden.

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, the National Environmental Policy Act, and the Coastal Zone Management Act require federal agencies to evaluate environmental issues in connection with granting such approvals and/or taking other major agency actions. The Outer Continental Shelf Lands Act, 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, the National Environmental Policy Act 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 Coastal Zone Management Act, 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, 2010, we had 561 full-time employees, including 28 senior level geoscientists and 52 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.

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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:

- changes in global supply and demand for oil and gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and gas;
- political and economic conditions, including embargoes, in oil-producing countries or affecting other oil-producing activity;
- the level of global oil and gas exploration and production activity;
- the level of global oil and gas inventories;
- weather conditions;
- technological advances affecting energy consumption;
- domestic and foreign governmental regulations;
- proximity and capacity of oil and gas pipelines and other transportation facilities;
- the price and availability of competitors' supplies of oil and gas in captive market areas; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically and therefore potentially lower our reserve bookings. 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.

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

Our future success will depend on the success of our 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:

- 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 and CO_2;
- equipment failures or accidents;
- adverse weather conditions, such as freezing temperatures, hurricanes and storms;
- reductions in oil and natural gas prices; and
- title problems.

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, 2010, undeveloped reserves comprised 36% of the North Ward Estes field's total estimated proved reserves. To fully develop these reserves, we expect to incur future development costs of $561.4 million at the North Ward Estes field as of December 31, 2010. This field encompasses 44% of our total estimated future development costs of $1,263.7 million 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 CO_2 injection installations, the success of which is less predictable than traditional development techniques.

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

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

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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 $9.4 million impairment write-down during 2009 for the partial impairment of producing properties, primarily natural gas, in the Rocky Mountains region. 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 taken.

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 oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes 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, 2010 would have decreased from $3,667.6 million to $3,664.5 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, 2010 would have decreased from $3,667.6 million to $3,600.5 million.

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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, 2010, we had $200.0 million in borrowings and $0.4 million in letters of credit outstanding under Whiting Oil and Gas Corporation's credit agreement with $899.6 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 may be at variable rates; 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 reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to 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 the assets of us and 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.

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:

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- 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:

- 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 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.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel 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.

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, 2010, 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 will 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 protection from sellers against them.

Our business strategy includes a continuing acquisition program. From 2004 through 2010, 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 future revenues from price increases and result in significant fluctuations in our net income.

We enter into hedging transactions of our oil and natural gas production 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 1, 2011, we had contracts, which include our 24.2% share of the Whiting USA Trust I hedges, covering the sale for 2011 of between 904,255 and 904,917 barrels of oil per month and between 34,554 and 38,139 MMBtu of natural gas per month. 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.

Effective April 1, 2009, we elected to de-designate all of our commodity derivative contracts that had been previously designated as cash flow hedges as of March 31, 2009 and have elected to discontinue hedge accounting prospectively. As such, subsequent to March 31, 2009 we recognize all gains and losses from prospective changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income. Subsequently, we may experience significant net income and operating result losses, on a non-cash basis, due to changes in the value of our hedges as a result of commodity price volatility.

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

Oil and gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas, drilling and other oil and gas activities can only be conducted during the spring and summer months. For example, our net production from the Sanish field averaged 22,270 BOE/d in December 2010, a 3% decrease from 22,935 BOE/d in September 2010, due to well completion delays caused by inclement weather in North Dakota. Conditions such as these can therefore limit 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.

The differential between the NYMEX or other benchmark price 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 to the relevant benchmark prices such as NYMEX. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. Increases in the differential 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.

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

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 underlying 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 timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. 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.

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

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, 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.

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

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

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

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

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 ("GHGs") present an endangerment to public heath 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. These findings allow the EPA to adopt and implement regulations that would restrict emissions of GHGs under existing provisions of the federal Clean Air Act. The EPA has adopted two sets of regulations under the Clean Air Act. The first limits emissions of GHGs from motor vehicles beginning with the 2012 model year. The EPA has asserted that these final motor vehicle GHG emission standards trigger Clean Air Act 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 according to "best available control technology" standards for GHGs that were published by the EPA in its PSD and Title V Permitting Guidance for Greenhouse Gases document in November 2010. Also in November 2010, the EPA expanded its existing GHG reporting rule to include onshore oil and natural gas production, processing, transmission, storage, and distribution facilities. This rule requires reporting of GHG emissions from such facilities on an annual basis with reporting beginning in 2012 for emissions occurring in 2011.

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In addition, both houses of Congress have actively considered legislation to reduce emissions of GHGs, and many states have already taken legal measures to reduce emissions of GHGs, 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 GHGs associated with our operations which will require us to incur costs to inventory and reduce emissions of GHGs associated with our operations and 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 GHGs in the atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events; if any such effects were to occur, they could have an adverse effect on our assets and operations.

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

The U.S. Congress is considering legislation that would amend the federal Safe Drinking Water Act by repealing an exemption for the underground injection of hydraulic fracturing fluids near drinking water sources. Hydraulic fracturing is an important and commonly used process for the completion of natural gas, and to a lesser extent, oil wells in shale formations, and involves the pressurized injection of water, sand and chemicals into rock formations to stimulate natural gas production. Sponsors of the legislation have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. If enacted, the legislation could result in additional regulatory burdens such as permitting, construction, financial assurance, monitoring, recordkeeping, and plugging and abandonment requirements. The legislation also proposes requiring the disclosure of chemical constituents used in the fracturing process to state or federal regulatory authorities, who would then make such information publicly available. The availability of this information could make it easier for third parties opposing the hydraulic fracturing process to initiate legal proceedings based on allegations that specific chemicals used in the fracturing process could adversely affect groundwater. In addition, various state and local governments are considering increased regulatory oversight of hydraulic fracturing through additional permit requirements, operational restrictions, and temporary or permanent bans on hydraulic fracturing in certain environmentally sensitive areas such as watersheds. The adoption of any federal or state legislation or implementing regulations imposing reporting obligations on, or otherwise limiting, the hydraulic fracturing process could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to perform hydraulic fracturing and increase our costs of compliance and doing business.

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.

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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.

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 as a result of future legislation.

In February 2010, President Obama's Administration released its proposed federal budget for fiscal year 2011 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 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.

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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 otherwise manage our financial risks related to volatility in oil and gas commodity prices.

Item 1B. Unresolved Staff Comments

None.

Item 2. Properties

Summary of Oil and Gas Properties and Projects

Permian Basin Region

Our Permian Basin operations include assets in Texas and New Mexico. As of December 31, 2010, the Permian Basin region contributed 123.6 MMBOE (94% oil) of estimated proved reserves to our portfolio of operations, which represented 41% of our total estimated proved reserves and contributed 12.3 MBOE/d of average daily production in December 2010.

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. The Yates Formation at 2,600 feet is the primary producing zone with additional production from other zones including the Queen at 3,000 feet. In the North Ward Estes field, the estimated proved reserves as of December 31, 2010 were 36% PDP, 28% PDNP and 36% PUD.

The North Ward Estes field is responding positively to our water and CO2 floods, which we initiated in May 2007. As of December 31, 2010, we were injecting over 240 MMcf/d of CO2 in this field. Production from the field has increased 9% from 7.0 MBOE/d in the fourth quarter of 2009 to 7.6 MBOE/d in the fourth quarter of 2010. 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 two phases were largely completed by March 2009, and Phase III began in December 2010. We plan to have all eight phases implemented by 2016.

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, 2010, we currently have under contract 52% of the future CO2 volumes that we believe necessary to develop the North Ward Estes proved undeveloped reserves, and we are in negotiations with suppliers to enter into long-term contracts that would secure the remaining quantities of CO2 needed to develop the proved reserves at this field. 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.

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Big Tex Prospect. As of December 31, 2010, Whiting had accumulated approximately 78,800 gross (66,200 net) acres in our Big Tex prospect area in Pecos, Reeves and Ward Counties, Texas in the Delaware Basin. Prospective formations include the Wolfcamp and Bone Spring horizons. We have drilled and completed five vertical wells in the Big Tex prospect, and we plan to begin a four-well horizontal drilling program in the second quarter of 2011. We consider this play to be in an early stage, and further drilling is subject to evaluation of our drilling and completion results.

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, 2010, our estimated proved reserves in the Rocky Mountain region were 121.6 MMBOE (78% oil), which represented 40% of our total estimated proved reserves and contributed 39.5 MBOE/d of average daily production in December 2010.

Sanish Field. Our Sanish area in Mountrail County, North Dakota encompasses approximately 109,200 gross (66,500 net) acres. Net production in the Sanish field averaged 23.5 MBOE/d in the fourth quarter of 2010, a 96% increase from 12.0 MBOE/d in the fourth quarter of 2009. Including non-operated wells, there were 197 producing wells in the Sanish field at year-end 2010, and as of February 15, 2011, 24 wells were in the process of completion and 11 wells were being drilled. Of the 197 wells, 72 were completed in 2010. In order to process the produced gas stream from the Sanish wells, we constructed and brought on-line the Robinson Lake Gas Plant. We expanded the plant during 2010, and in December 2010 we added additional equipment which brought the plant's inlet capacity to 60 MMcf/d. We intend to further expand the plant in order to increase our processing capability to 90 MMcf/d in the third quarter of 2011. We completed the installation of the 17-mile oil line connecting the Sanish field to the Enbridge pipeline in Stanley, North Dakota in late December 2009. As of December 31, 2010, the pipeline was moving approximately 27,200 Bbls of oil per day. This 8-inch diameter line has a daily capacity of approximately 65,000 barrels of oil per day. We expect to have substantially all of our operated production flowing through the pipeline into the Enbridge facility by the second quarter of 2011.

Parshall Field. Immediately east of the Sanish field is the Parshall field, where we own interests in approximately 73,100 gross (18,200 net) acres. Our net production from the Parshall field averaged 4.6 MBOE/d in the fourth quarter of 2010, a 32% decrease from 6.7 MBOE/d in the fourth quarter of 2009. As of February 15, 2011, we have participated in 127 Bakken wells in the Parshall field, the majority of which are operated by EOG Resources, Inc., all of which are producing. Of these wells, one operated well was completed in 2010.

Lewis & Clark Prospect. As of December 31, 2010, we have assembled approximately 360,500 gross (234,900 net) acres in our Lewis & Clark prospect along the Bakken Shale pinch-out in the southern Williston Basin. During 2010 we assembled acreage located primarily in Stark County, North Dakota. 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 Three Forks formation. We hold a working interest in 250 1,280-acre spacing units, and we estimate two to four wells per unit to fully develop this area. As of December 31, 2010, we had drilled seven horizontal wells into the Three Forks reservoir at Lewis & Clark, and the average production from these seven wells was approximately 0.6 MBOE/d during the first 30 days of production. We currently have five drilling rigs operating in this area, and we plan to double this rig count by the end of 2011. In January 2011, we also added a full-time dedicated fracture stimulation crew that will focus on the Lewis & Clark area. In addition, we recently broke ground on the construction of a gas processing plant at Lewis & Clark, which is expected to be completed in November 2011.

Flat Rock Field. We acquired the Flat Rock Field in May 2008 and took over operations June 1, 2008. In the Flat Rock field area in Uintah County, Utah, we have an acreage position consisting of approximately 22,000 gross (11,500 net) acres. During 2010, we drilled four successful wells in the field.

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Redtail Niobrara Prospect. As of December 31, 2010, we had approximately 89,400 gross (66,100 net) acres in our Redtail Niobrara prospect in the Weld County, Colorado portion of the DJ Basin. In late 2010, we initiated a seven well exploratory drilling program in the Niobrara that will continue through June of 2011 and will consist of two vertical pilot wells and five horizontal production wells. Based on our current acreage position and a successful exploratory program, we could operate up to 220 wells and participate in an additional 131 non-operated wells assuming 320-acre spacing. We have drilled four Niobrara wells as of February 15, 2011. However, this play is in an early stage, and further drilling is subject to evaluation of our drilling and completion results.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. As of December 31, 2010, the Mid-Continent region contributed 41.5 MMBOE (92% oil) of proved reserves to our portfolio of operations, which represented 14% of our total estimated proved reserves and contributed 9.2 MBOE/d of average daily production in December 2010. 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. Our expansion of the CO2 flood at the Postle field continues to generate positive results. As of December 31, 2010, we were injecting 140 MMcf/d of CO2 in this field. Production from the field maintained an average net rate of 8.9 MBOE/d in the fourth quarter of 2010 and 2009. 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. However, the production response can be diminished during periods of high water injection. A number of patterns were cycled to water injection during the third and fourth quarters of 2010, which caused a normal slowing of oil response. Operations are underway to expand CO2 injection into the northern part of the fourth unit, HMU, and to optimize flood patterns in the existing CO2 floods. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells. In the Postle field, the estimated proved reserves as of December 31, 2010 were 93% PDP, 2% PDNP and 5% 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 for the expansion planned in the field.

Gulf Coast Region

Our Gulf Coast operations include assets located in Texas, Louisiana and Mississippi. As of December 31, 2010, the Gulf Coast region contributed 9.4 MMBOE (34% oil) of proved reserves to our portfolio of operations, which represented 3% of our total estimated proved reserves and contributed 2.7 MBOE/d of average daily production in December 2010.

Eagle Ford Trend. We own acreage in the Nordheim, Word North, Yoakum, Kawitt, Sweet Home, and Three Rivers fields along the Eagle Ford Trend in Karnes, Dewitt, Live Oak and Lavaca Counties, Texas. In 2007, we farmed out the Kawitt and Nordheim lease position to another operator who is developing the Eagle Ford Trend with horizontal wellbores. Under the terms of this agreement, we were carried on all drilling and completion costs on four Eagle Ford Trend wells, and Whiting maintained a 16.67% working interest in the completed wells. Going forward, we had the option to participate upfront for a 25% working interest in additional wells to be drilled or elect to take the 25% working interest after payout has occurred. To date, we have elected to take a 25% after payout working interest in seven wells drilled under this farmout. The operator has been successful in drilling Eagle Ford wells and by December 31, 2010 had drilled and completed ten wells. Our net production from the area was 5.3 MMcf/d in December 2010.

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Michigan Region

As of December 31, 2010, our estimated proved reserves in the Michigan region were 8.8 MMBOE (32% oil), and our December 2010 daily production averaged 2.8 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.

Marion 3-D Project. The Marion Prospect, located in Missaukee, Clare and Osceola Counties, Michigan, covers approximately 16,000 gross (14,700 net) acres. Analysis of seismic data identified two drillable prospects, and in late 2010, we drilled one of these prospects and are in the process of completing the well. The second prospect will be drilled in early 2011.

Reserves

As of December 31, 2010, 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, 2010 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, 2010) 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	178,409	220,530	215,164
Undeveloped	75,869	83,014	89,705
Total proved—December 31, 2010	254,278	303,544	304,869
Probable reserves			
Developed	1,850	10,864	3,661
Undeveloped	62,856	201,337	96,412
Total probable—December 31, 2010	64,706	212,201	100,073
Possible reserves			
Developed	16,149	8,407	17,550
Undeveloped	166,866	196,358	199,592
Total possible—December 31, 2010	183,015	204,765	217,142

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 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 extended the proved acreage in that area.

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 our 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 estimates since those wells are no longer planned to be drilled due to continued low gas prices.

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Proved undeveloped reserves. From December 31, 2009 to December 31, 2010, our proved undeveloped reserves ("PUDs") decreased 11% or 10.7 MMBOE. This decrease in proved undeveloped reserves was primarily attributable to PUDs being converted to proved developed at the Sanish and North Ward Estes fields, and such decrease was partially offset by PUD locations added at the Sanish field. The Sanish PUD conversion was the result of our active drilling program in that field during 2010. The PUD conversion at North Ward Estes was due to the continuing expansion of our CO2 enhanced recovery project in that field. There were 25.8 MMBOE of PUDs that were converted into proved developed reserves due to 71 proved undeveloped well locations that were drilled and placed on production during 2010. We incurred $208.7 million in capital expenditures, or $8.09 per BOE, to drill and bring on-line these 71 PUD locations. In addition, there were approximately 18.2 MMBOE of PUDs that became proved developed reserves in 2010 at our CO2 enhanced recovery projects in the Postle and North Ward Estes fields. These PUDs were converted to proved developed at a cost of approximately $15.11 per BOE. Combining the PUD drilling conversions with the PUD enhanced oil recovery conversions, the Company converted 44.0 MMBOE of PUDs to proved developed reserves during 2010 at a cost of $10.99 per BOE.

Based on our 2010 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 2010 were primarily attributable to (i) 32 new probable undeveloped well locations, which were added in 2010 as a result of our drilling activity on newly acquired acreage in North Dakota, and (ii) new probable undeveloped reserves assigned to the expansion of our CO2 enhanced recovery project in the Postle field.

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

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

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

Possible reserves increased during 2010 primarily due to the acquisition of new producing properties south of our North Ward Estes field in 2010. We plan on carrying out waterflood and CO2 enhanced recovery projects on these newly acquired fields, and such projects have possible reserves associated with them.

At December 31, 2010, our probable reserves were estimated to be 100.1 MMBOE and our possible reserves were estimated to be 217.1 MMBOE, for a total of 317.2 MMBOE. The enhanced oil recovery (“EOR”) project at our North Ward Estes field represented 130.2 MMBOE, or 41%, of our total 317.2 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.

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CG&A is a Texas Registered Engineering Firm. Our primary contact at CG&A is Mr. Robert Ravnaas, Executive Vice 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 37 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.

Acreage

The following table summarizes gross and net developed and undeveloped acreage by state at December 31, 2010. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross(2)	Net(2)	Gross	Net
California	25,548	3,606	-	-	25,548	3,606
Colorado	44,868	23,635	120,387	78,643	165,255	102,278
Louisiana	40,064	7,479	3,990	2,112	44,054	9,591
Michigan	138,575	62,164	24,271	19,694	162,846	81,858
Montana	42,222	13,786	129,987	102,798	172,209	116,584
North Dakota	342,733	172,586	454,849	292,500	797,582	465,086
Oklahoma	90,908	59,337	772	471	91,680	59,808
Texas	254,085	139,090	124,557	103,211	378,642	242,301
Utah	23,571	14,403	254,677	60,790	278,248	75,193
Wyoming	97,153	56,223	74,325	48,874	171,478	105,097
Other(1)	15,251	8,470	2,872	1,695	18,123	10,165
Total	1,114,978	560,779	1,190,687	710,788	2,305,665	1,271,567

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

(2) Out of a total of approximately 1,190,700 gross (710,800 net) undeveloped acres as of December 31, 2010, the portion of our net undeveloped acres that is subject to expiration over the next three years, if not successfully developed or renewed, is approximately 10% in 2011, 7% in 2012, and 21% in 2013.

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Production History

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

	Year Ended December 31,		
	2010	2009	2008
Oil production (MMBbls)	19.0	15.4	12.4
Natural gas production (Bcf)	27.4	29.3	30.4
Total production (MMBOE)	23.6	20.3	17.5
Daily production (MBOE/d)	64.6	55.5	47.9
North Ward Estes field production (1)			
Oil production (MMBbls)	2.7	2.2	1.9
Natural gas production (Bcf)	0.4	0.6	1.2
Total production (MMBOE)	2.8	2.3	2.1
Sanish field production (1)			
Oil production (MMBbls)	6.8	3.7	1.6
Natural gas production (Bcf)	2.5	1.3	0.1
Total production (MMBOE)	7.2	3.9	1.6
Average sales prices:			
Oil (per Bbl)	$70.53	$52.51	$86.99
Natural gas (per Mcf)	$4.86	$3.75	$7.68
Average production costs:			
Production costs (per BOE) (2)	$10.62	$11.10	$12.81

(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, 2010.

(2) Production costs reported above exclude from lease operating expenses ad valorem taxes of $17.7 million ($0.75 per BOE), $12.2 million ($0.61 per BOE), and $16.8 million ($0.96 per BOE) for the years ended December 31, 2010, 2009 and 2008, respectively.

Productive Wells

The following table summarizes gross and net productive oil and natural gas wells by region at December 31, 2010. 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
Permian Basin	3,970	1,728	398	132	4,368	1,860
Rocky Mountains	2,341	554	478	264	2,819	818
Mid-Continent	578	368	200	82	778	450
Gulf Coast	96	53	461	117	557	170
Michigan	77	41	1,099	416	1,176	457
Total	7,062	2,744	2,636	1,011	9,698	3,755

(1) 143 wells are multiple completions. These 143 wells contain a total of 352 completions. One or more completions in the same bore hole are counted as one well.

We have an interest in or operate 34 enhanced oil recovery projects, which include both secondary (waterflood) and tertiary (CO_2 injection) recovery efforts, and aggregate production from such enhanced oil recovery fields averaged 17.9 MBOE/d during 2010 or 28% of our 2010 daily production. For these areas, we need to use enhanced recovery techniques in order to maintain oil and gas production from these fields.

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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
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
2008:						
Development	283	20	303	113.3	9.2	122.5
Exploratory	2	3	5	1.9	1.3	3.2
Total	285	23	308	115.2	10.5	125.7

As of December 31, 2010, 22 operated drilling rigs and 43 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:

Region	Drilling	Workover
Rocky Mountain	17	8
Permian	2	3
Mid-Continent/Michigan	-	2
North Ward Estes	-	26
Postle	2	4
Gulf Coast	1	-
Total	22	43

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, 2010, we had delivery commitments of 10.5 Bcf (or 38% of total 2010 natural gas production), 5.7 Bcf (21%) and 4.4 Bcf (16%) for the years ended December 31, 2011, 2012 and 2013, respectively. These contracts were related to production at our Boies Ranch field in Rio Blanco County, Colorado, at our Antrim Shale wells in Michigan and at 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.

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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.

In November 2010, Whiting previously disclosed a well incident at the Roggenbuck 14-25H well in North Dakota in which a valve near the well head failed resulting in water, oil and natural gas flowing from the well, with Whiting containing and hauling from the well site the liquids being produced. Whiting received a complaint, dated February 15, 2011, in an administrative action by the North Dakota Industrial Commission alleging that in connection with such incident Whiting violated certain sections of the North Dakota Administrative Code governing the oil and gas industry, including by not controlling subsurface pressure on a well, by allowing oil and brine to flow over and pool on the surface of the land and by not properly maintaining a dike on the well site. The complaint requests that Whiting pay aggregate fines of $162,500 and costs and expenses of $4,357. The incident described above was of relatively short duration, was fully and promptly remediated, and there were no injuries. Whiting intends to investigate the assertions set forth in the complaint and respond as appropriate.

Item 4. Reserved

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 15, 2011, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	64	Chairman and Chief Executive Officer
James T. Brown	58	President and Chief Operating Officer
Mark R. Williams	54	Senior Vice President, Exploration and Development
Bruce R. DeBoer	58	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	40	Vice President, Human Resources
Jack R. Ekstrom	64	Vice President, Corporate and Government Relations
J. Douglas Lang	61	Vice President, Reservoir Engineering and Acquisitions
Rick A. Ross	52	Vice President, Operations
David M. Seery	56	Vice President, Land
Michael J. Stevens	45	Vice President and Chief Financial Officer
Brent P. Jensen	41	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 39 years of experience in the oil and gas industry. Mr. Volker has a 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 36 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 30 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 our 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 31 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 14 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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Jack R. Ekstrom joined us in September 2008 as Executive Director, Corporate Communications and Investor Relations, and became Vice President, Corporate and Government Relations in January 2010. From 2004 to 2008, Mr. Ekstrom served as the Director of Government Affairs for Pioneer Natural Resources, an independent oil and gas exploration and production company. Prior to this he served as the Director of Government Affairs for Evergreen Resources and Forest Oil. He has 36 years of experience in the oil and gas industry. Mr. Ekstrom is a Director of the Colorado Oil & Gas Association and the Western Energy Alliance, and is a past chairman of the Western Business Roundtable and past president of the Denver Petroleum Club. He holds a Bachelor of Arts Degree in Communications from Augustana College in Rock Island, Illinois.

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 37 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 28 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 30 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 24 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 17 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, 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
Fiscal Year Ended December 31, 2009		
Fourth Quarter (Ended December 31, 2009)	$37.83	$26.34
Third Quarter (Ended September 30, 2009)	$29.71	$14.89
Second Quarter (Ended June 30, 2009)	$24.97	$12.27
First Quarter (Ended March 31, 2009)	$22.50	$9.63

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 share and per share amounts in this Annual Report on Form 10-K have been retroactively adjusted to reflect the stock split for all periods presented.

On February 22, 2011, there were 747 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, 2005 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, 2005 in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones US Oil Companies, Secondary Index.

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	12/31/05	12/31/06	12/31/07	12/31/08	12/31/09	12/31/10
Whiting Petroleum Corporation	$ 100	$ 117	$ 144	$ 84	$ 179	$ 293
Standard & Poor’s Composite 500 Index	$ 100	$ 114	$ 118	$ 72	$ 89	$ 101
Dow Jones US Oil Companies, Secondary Index	$ 100	$ 105	$ 149	$ 89	$ 123	$ 143

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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, 2010, 2009 and 2008 and the consolidated balance sheet information at December 31, 2010 and 2009 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, 2007 and 2006 and the consolidated balance sheet information at December 31, 2008, 2007 and 2006 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: Redtail Prospect, September 1, 2010; Additional interests in North Ward Estes, November 1, 2009 and October 1, 2009; Flat Rock Natural Gas Field, May 30, 2008; and Michigan Properties, August 15, 2006.

	Year Ended December 31,				
	2010	2009	2008	2007	2006
	(dollars in millions, except per share data)				
Consolidated Statements of Income Information:					
Revenues and other income:					
Oil and natural gas sales	$ 1,475.3	$ 917.5	$ 1,316.5	$ 809.0	$ 773.1
Gain (loss) on hedging activities	23.2	38.8	(107.6)	(21.2)	(7.5)
Amortization of deferred gain on sale	15.6	16.6	12.1	—	—
Gain on sale of properties	1.4	5.9	—	29.7	12.1
Interest income and other	0.6	0.6	1.1	1.2	1.1
Total revenues and other income	1,516.1	979.4	1,222.1	818.7	778.8
Costs and expenses:					
Lease operating	268.3	237.3	241.2	208.9	183.6
Production taxes	103.9	64.7	87.5	52.4	47.1
Depreciation, depletion and amortization	393.9	394.8	277.5	192.8	162.8
Exploration and impairment	59.4	73.0	55.3	37.3	34.5
General and administrative	64.7	42.3	61.7	39.0	37.8
Interest expense	59.1	64.6	65.1	72.5	73.5
Loss on early extinguishment of debt	6.2	—	—	—	—
Change in Production Participation Plan liability	12.1	3.3	32.1	8.6	6.2
	7.1	262.2	(7.1)	—	—

Commodity derivative (gain) loss, net					
Total costs and expenses	974.7	1,142.2	813.3	611.5	545.5
Income (loss) before income taxes	541.4	(162.8)	408.8	207.2	233.3
Income tax expense (benefit)	204.8	(55.9)	156.7	76.6	76.9
Net income (loss)	336.7	(106.9)	252.1	130.6	156.4
Preferred stock dividends	(64.0)	(10.3)	—	—	—
Net income (loss) available to common shareholders	$ 272.7	$ (117.2)	$ 252.1	$ 130.6	$ 156.4
Earnings (loss) per common share, basic(1)	$ 2.57	$ (1.18)	$ 2.98	$ 1.65	$ 2.13
Earnings (loss) per common share, diluted(1)	$ 2.55	$ (1.18)	$ 2.97	$ 1.65	$ 2.12
Other Financial Information:					
Net cash provided by operating activities	$ 997.3	$ 453.8	$ 766.5	$ 394.0	$ 411.2
Net cash used in investing activities	$ (914.6)	$ (523.5)	$ (1,138.5)	$ (467.0)	$ (527.6)
Net cash (used in) provided by financing activities	$ (75.7)	$ 72.1	$ 366.8	$ 77.3	$ 116.4
Capital expenditures	$ 923.8	$ 585.8	$ 1,330.9	$ 519.6	$ 552.0
Consolidated Balance Sheet Information:					
Total assets	$ 4,648.8	$ 4,029.5	$ 4,029.1	$ 2,952.0	$ 2,585.4
Long-term debt	$ 800.0	$ 779.6	$ 1,239.8	$ 868.2	$ 995.4
Total stockholders' equity	$ 2,531.3	$ 2,270.1	$ 1,808.8	$ 1,490.8	$ 1,186.7

(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 have been retroactively adjusted to reflect the stock split for all periods presented.

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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 Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan 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.

Although oil prices fell significantly after reaching a high in the third quarter of 2008, they experienced a rebound in the second half of 2009 and throughout 2010. Additionally, natural gas prices have fallen significantly since their peak in the third quarter of 2008 and have remained low throughout 2009 and 2010. The following table highlights these price trends by listing quarterly average NYMEX crude oil and natural gas prices for the periods indicated:

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	2008		2009				2010			
	Q3	Q4	Q1	Q2	Q3	Q4	Q1	Q2	Q3	Q4
Crude Oil	$ 118.13	$ 58.75	$ 43.21	$ 59.62	$ 68.29	$ 76.17	$ 78.79	$ 77.99	$ 76.21	$ 85.18
Natural Gas	$ 10.27	$ 6.96	$ 4.92	$ 3.50	$ 3.40	$ 4.16	$ 5.30	$ 4.09	$ 4.39	$ 3.81

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 reserve bookings. 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 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 recognized on our commodity 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, 2009 to December 31, 2010 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.

2010 Highlights and Future Considerations

Operational Highlights. Our Sanish and Parshall fields in Mountrail County, North Dakota target the Bakken and Three Forks formations. Net production in the Sanish field increased 96% from 12.0 MBOE/d in the fourth quarter of 2009 to 23.5 MBOE/d in the fourth quarter of 2010. Based on results of our microseismic studies and reservoir pressure monitoring in both the Bakken and Three Forks formations, we believe that additional infill drilling is necessary to maximize primary recovery in the Sanish field. As a result, we have increased by 153 the total number of gross operated wells that we expect to drill in the Sanish field to 535 gross wells from 382 gross wells previously planned. We have also elected to drill three Three Forks wells per 1,280-acre unit as compared to our previous plan of two Three Forks wells per unit. This decision adds 80 potential gross well locations in the Sanish field. Including non-operated wells, we estimate that over 300 gross wells remain to be drilled in the Sanish field as of February 15, 2011.

During 2010, we completed 72 operated wells in the Sanish field, bringing to 136 the total number of operated wells in the field as of December 31, 2010. As of February 15, 2011, 20 operated wells were being completed or awaiting completion and nine operated wells were being drilled in the Sanish field. In 2011, we intend to drill or participate in the drilling of a total of 95 gross (54 net) operated wells in the Sanish field, of which 70 will target the Three Forks formation and 25 will target the Bakken formation.

Net production in the Parshall field decreased 32% from 6.7 MBOE/d in the fourth quarter of 2009 to 4.6 MBOE/d in the fourth quarter of 2010. This production decrease was primarily due to normal field production decline and reduced drilling in the area as the operator of the Parshall field has drilled almost all of its Bakken locations and is currently pursuing a moderate pace of development of the Three Forks formation with a one-rig program.

As of December 31, 2010, we have assembled approximately 360,500 gross (234,900 net) acres in the Lewis & Clark area, which is located primarily in Stark County, North Dakota and which acreage runs 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 Three Forks formation. We hold a working interest in 250 1,280-acre spacing units in Lewis & Clark, and we estimate two to four wells per 1,280-acre spacing unit to fully develop this area. As of December 31, 2010, we had drilled seven horizontal wells into the Three Forks reservoir at Lewis & Clark, and the average production from these seven wells was approximately 0.6 MBOE/d during the first 30 days of production. We currently have five drilling rigs operating in this prospect, and we plan to double this rig count by the end of 2011. In January 2011, we also added a full-time dedicated fracture stimulation crew that will focus on the Lewis & Clark area. In addition, we recently broke ground on the construction of a gas processing plant at Lewis & Clark, which is expected to be completed in November 2011.

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We continue to have significant development and related infrastructure activity in the Postle and North Ward Estes fields acquired in 2005, which have resulted in reserve additions and production increases. Our expansion of the CO2 floods at both fields continues to generate positive results.

Production from the Postle field, which is located in Texas County, Oklahoma and produces from the Morrow sandstone, maintained an average net rate of 8.9 MBOE/d for the fourth quarter of 2010 and 2009. 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; however, the production response can be diminished during periods of high water injection. A number of patterns were cycled to water injection during the third and fourth quarters of 2010, which caused a normal slowing of oil response. The effect of the increased water injection and loss of CO2 injection resulted in production declines in the second half of 2010. We estimate that the production volumes at Postle will return to their previous range of 9.1 to 9.4 MBOE/d by mid-2011. We are forecasting that Postle production will plateau at about this level for approximately 18 to 24 months.

The North Ward Estes field is located in Ward and Winkler Counties, Texas and is responding positively to our water and CO2 floods, which we initiated in May 2007. In early March 2009, we expanded the area of our CO2 injection project. Net production from the field increased 9% from 7.0 MBOE/d in the fourth quarter of 2009 to 7.6 MBOE/d in the fourth quarter of 2010. In this field, we plan to install oil, gas and water processing facilities in eight phases. The first two phases were largely completed by December 2009, and Phase III began in December 2010. We plan to have all eight phases implemented by 2016.

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 share and per share amounts in this Annual Report on Form 10-K have been retroactively adjusted to reflect the stock split for all periods presented.

In September 2010, we paid $383.5 million to redeem all of our $150.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2012 and all of our $220.0 million aggregate principal amount of 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. We financed the redemption of the 2012 and 2013 notes with borrowings under our credit agreement. As a result of the redemption, we 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.

In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. We used the net proceeds from this issuance to repay a portion of the debt under our credit agreement, which was borrowed to redeem our 2012 and 2013 notes.

In August 2010, we commenced an offer to exchange up to 3,277,500, or 95%, of our outstanding 6.25% convertible perpetual preferred stock ("preferred stock") for the following consideration per share of preferred stock: 4.6066 shares of our common stock and a cash premium of $14.50. The exchange offer expired in September 2010 and resulted in 3,277,500 shares of preferred stock being exchanged for the issuance of 15,098,020 shares of our 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.

2011 Capital Budget and Major Development Areas. Our current 2011 capital budget is $1,350.0 million, and included in this amount is approximately $110.0 million in acreage acquisition costs. Previously we have not included acreage acquisition costs in our annual capital budgets. However, during 2010 we incurred $155.5 million in aggregate acreage purchases and have therefore decided to include such costs in our capital budgets going forward. We expect to fund substantially all of our 2011 capital budget using net cash provided by our operating activities. We have increased our capital budget for 2011 as compared to our actual capital expenditures incurred in 2010 in response to the higher oil prices experienced throughout 2010 and continuing into the first part of 2011, as well as in response to higher crude oil production volumes. 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 2011 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.

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Development Area	2011 Planned Capital Expenditures (In millions)
Northern Rockies	$707.0
CO2 projects (1)	314.0
Permian	92.0
Central Rockies	52.0
Gulf Coast	2.0
Michigan	5.0
Land	110.0
Exploration (2)	40.0
Other	28.0
Total	$1,350.0

(1) 2011 planned capital expenditures at our CO2 projects include $46.6 million for North Ward Estes CO2 purchases and $5.0 million for Postle CO2 purchases.

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

Acquisition and Divestiture Highlights

Whiting USA Trust I. On April 30, 2008, we completed an initial public offering of units of beneficial interest in Whiting USA Trust I (the "Trust"), selling 11,677,500 Trust units at $20.00 per Trust unit, and providing net proceeds of $193.8 million after underwriters' fees, offering expenses and post-close adjustments. We used the offering net proceeds to repay a portion of the debt outstanding under our credit agreement. The net proceeds from the sale of Trust units to the public resulted in a deferred gain on sale of $100.2 million. Immediately prior to the closing of the offering, we conveyed a term net profits interest in certain of our oil and gas properties to the Trust in exchange for 13,863,889 Trust units. We have retained 15.8%, or 2,186,389 Trust units, of the total Trust units issued and outstanding.

The net profits interest entitles the Trust to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate at the time when 9.11 MMBOE have been produced and sold from the underlying properties. This is the equivalent of 8.2 MMBOE in respect of the Trust's right to receive 90% of the net proceeds from such production pursuant to the net profits interest. The conveyance of the net profits interest to the Trust consisted entirely of proved developed producing reserves of 8.2 MMBOE, as of the January 1, 2008 effective date, representing 3.3% of our proved reserves as of December 31, 2007, and 10.0% (4.2 MBOE/d) of our March 2008 average daily net production. After netting our ownership of 2,186,389 Trust units, third-party public Trust unit holders receive 6.9 MMBOE of proved producing reserves, or 2.75% of our total year-end 2007 proved reserves, and 7.4% (3.1 MBOE/d) of our March 2008 average daily net production.

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Results of Operations

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

	Year Ended December 31, 2010	2009	2008
Net production:			
Oil (MMBbls)	19.0	15.4	12.4
Natural gas (Bcf)	27.4	29.3	30.4
Total production (MMBOE)	23.6	20.3	17.5
Net sales (in millions):			
Oil (1)	$1,342.2	$807.6	$1,082.8
Natural gas (1)	133.1	109.9	233.7
Total oil and natural gas sales	$1,475.3	$917.5	$1,316.5
Average sales prices:			
Oil (per Bbl)	$70.53	$52.51	$86.99
Effect of oil hedges on average price (per Bbl)	(1.34)	(0.43)	(8.58)
Oil net of hedging (per Bbl)	$69.19	$52.08	$78.41
Average NYMEX price (per Bbl)	$79.55	$61.93	$97.24
Natural gas (per Mcf)	$4.86	$3.75	$7.68
Effect of natural gas hedges on average price (per Mcf)	0.04	0.05	-
Natural gas net of hedging (per Mcf)	$4.90	$3.80	$7.68
Average NYMEX price (per Mcf)	$4.39	$3.99	$9.06
Cost and expense (per BOE):			
Lease operating expenses	$11.37	$11.71	$13.77
Production taxes	$4.40	$3.19	$5.00
Depreciation, depletion and amortization expense	$16.69	$19.48	$15.84
General and administrative expenses	$2.74	$2.09	$3.52

(1) Before consideration of hedging transactions.

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 sales prices. 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 at 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 in 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 February 22, 2011.

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Gain (Loss) on Hedging Activities. Our gain on hedging activities decreased $15.6 million in 2010 as compared to 2009. The components of our gain on hedging activities were as follows (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 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. 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 February 22, 2011.

Lease Operating Expenses. Our lease operating expenses ("LOE") during 2010 were $268.3 million, a $31.1 million or 13% increase over the same period in 2009. This higher amount of 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 amounted 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. 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 are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take advantage of credits and exemptions allowed in our various taxing jurisdictions. Our production taxes during 2010 were $103.9 million, a $39.2 million increase over the same period in 2009, primarily due to higher oil and natural gas sales between periods. Our company-wide production tax rates for 2010 and 2009 were 7.0% of oil and natural gas sales.

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

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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. This factor was partially offset by $790.0 million in drilling and development expenditures incurred 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. 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.

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 Production Participation Plan (the “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.

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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 as of March 31, 2009 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.

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 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. Our effective income tax rate increased from 34.4% for 2009 to 37.8% for 2010. The change in the effective income tax rate between periods was primarily due to the change from 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.

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Year Ended December 31, 2009 Compared to Year Ended December 31, 2008

Oil and Natural Gas Sales. Our oil and natural gas sales revenue decreased $398.9 million to $917.5 million in 2009 compared to 2008. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 24% between periods, while our natural gas sales volumes decreased 4%. The oil volume increase resulted primarily from drilling success in the North Dakota Bakken area, in addition to increased production at our two large CO2 projects, Postle and North Ward Estes. Oil production from the Bakken increased 2,505 MBbl compared to 2008, while Postle oil production increased 695 MBbl and North Ward Estes oil production increased 365 MBbl over the same period in 2008. These production increases were partially offset by the Whiting USA Trust I (the “Trust”) divestiture, which decreased oil production by 435 MBbl. The gas volume decline between periods was primarily the result of the Trust divestiture, which decreased gas production in 2009 by 2,220 MMcf, as well as normal field decline. These decreases were partially offset by incremental gas production in 2009 of 1,370 MMcf from the Flat Rock acquisition and higher gas production in 2009 as compared to 2008 in the Bakken and Boies Ranch areas of 1,652 MMcf and 1,165 MMcf, respectively. Our average price for oil before the effects of hedging decreased 40% between periods, and our average price for natural gas before effects of hedging decreased 51%.

Gain (Loss) on Hedging Activities. Our gain on hedging activities increased $146.3 million in 2009 as compared to 2008. The components of our gain (loss) on hedging activities were as follows (in thousands):

	Year Ended December 31, 2009	2008
Gains reclassified from AOCI on de-designated hedges	$25,326	$-
Realized cash settlement gain (loss) on crude oil hedges	13,450	(107,555)
Total	$38,776	$(107,555)

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

Lease Operating Expenses. Our lease operating expenses during 2009 were $237.3 million, a $4.0 million or 2% decrease over the same period in 2008. Our lease operating expenses per BOE decreased from $13.77 during 2008 to $11.71 during 2009. The decrease of 15% on a BOE basis was primarily caused by increased production and a decrease of $14.6 million in electric power and fuel costs during 2009 as compared to 2008, partially offset by a high level of workover activity. Workovers amounted to $49.8 million in 2009, as compared to $27.3 million of workover activity during 2008. The increase in workover activity is a result of a higher number of service wells and producing wells in our CO2 projects.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales before the effects of hedging. We take advantage of credits and exemptions allowed in our various taxing jurisdictions. Our production taxes during 2009 were $64.7 million, a $22.9 million decrease over the same period in 2008, primarily due to lower oil and natural gas sales. Our production taxes for 2009 and 2008 were 7.0% and 6.7%, respectively, of oil and natural gas sales. Our production tax rate for 2009 was greater than in 2008 mainly due to successful wells that were completed in the North Dakota Bakken area during the latter half of 2008 and 2009 and that carry an 11.5% production tax rate.

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Depreciation, Depletion and Amortization. Our depreciation, depletion and amortization ("DD&A") expense increased $117.3 million as compared to 2008. The components of DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2009	2008
Depletion	$384,519	$270,770
Depreciation	3,147	3,439
Accretion of asset retirement obligations	7,126	3,239
Total	$394,792	$277,448

DD&A increased $117.3 million primarily due to $113.7 million in higher depletion expense between periods. Of this $113.7 million increase in depletion, $42.5 million related to higher oil and gas volumes produced during 2009, while $71.2 million related to our higher depletion rate in 2009. On a BOE basis, our DD&A rate increased by 23% from $15.84 for 2008 to $19.48 for 2009. The primary factor causing this rate increase between periods was a net reduction in our proved reserves of 11.6 MMBOE in the fourth quarter of 2008, which was primarily attributable to a 39.0 MMBOE downward revision in reserves for lower oil and natural gas prices as of December 31, 2008. This significant downward adjustment to reserves drove our DD&A rate substantially higher during the fourth quarter of 2008 and for the first three quarters of 2009, as compared to our DD&A rate during the first three quarters of 2008. Our DD&A rate for the first nine months of 2008 was lower because it was computed based on proved oil and gas reserves as of December 31, 2007 that incorporated much higher oil and natural gas pricing. In addition to this primary factor affecting our DD&A rate between periods, our DD&A rate remained consistently higher in all of 2009 due to (i) $432.9 million in drilling expenditures incurred during the year and (ii) $77.4 million of cash acquisition capital expenditures that were incurred during 2009 and transferred to the proved property amortization base.

Exploration and Impairment Costs. Our exploration and impairment costs increased $17.8 million, as compared to 2008. The components of exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2009	2008
Exploration	$46,875	$29,302
Impairment	26,139	25,955
Total	$73,014	$55,257

Exploration costs increased $17.6 million during 2009 as compared to 2008 primarily due to higher exploratory dry hole expense and rig termination fees recognized during 2009. During 2009, we drilled three exploratory dry holes in the Rocky Mountains region totaling $18.2 million, while during the same period in 2008 we drilled one exploratory dry hole in the Permian region and participated in two non-operated exploratory dry holes in the Rocky Mountains region totaling $3.6 million. Rig termination fees totaled $6.5 million during 2009, as compared to $0.8 million during 2008. Impairment expense in 2009 includes $9.4 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, as compared to $10.9 million in non-cash impairment expense in 2008 for the partial write-down of unproved properties in the central Utah Hingeline play.

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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, 2009	2008
General and administrative expenses	$92,837	$103,231
Reimbursements and allocations	(50,480)	(41,547)
General and administrative expense, net	$42,357	$61,684

General and administrative expense before reimbursements and allocations decreased $10.4 million to $92.8 million during 2009. The largest components of the decrease related to $20.5 million in lower employee compensation between periods related to accrued distributions under our Production Participation Plan (the “Plan”). Accrued distributions under the Plan decreased in 2009 due to (i) a lower level of Plan net revenues (which have been reduced by lease operating expenses and production taxes pursuant to the Plan formula) resulting from lower oil and natural gas prices during 2009 as compared to 2008, and (ii) the Trust divestiture completed in April 2008 which increased 2008 accrued distributions under the Plan. These lower accrued Plan distributions were partially offset by $8.9 million in additional employee compensation in 2009 for personnel hired during the year as well as for general pay increases. The increase in reimbursements and allocations in 2009 was primarily caused by higher salary costs and a greater number of field workers on operated properties. Our general and administrative expenses, net as a percentage of oil and natural gas sales remained consistent at 5% for 2008 and 2009.

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

	Year Ended December 31, 2009	2008
Senior Subordinated Notes	$43,907	$43,461
Credit Agreement	12,891	18,377
Amortization of debt issue costs and debt discount	11,027	4,801
Other	189	1,568
Capitalized interest	(3,406)	(3,129)
Total	$64,608	$65,078

The decrease in interest expense of $0.5 million between periods was mainly due to a lower effective cash interest rate and lower borrowings outstanding under our credit agreement. This decrease was partially offset by higher debt issue cost amortization associated with additional issuance costs incurred in April 2009 when renewing our credit agreement. Our weighted average effective cash interest rate was 5.7% during 2009 compared to 5.9% during 2008. Our weighted average debt outstanding during 2009 was $1,008.5 million versus $1,049.4 million for 2008.

Commodity Derivative (Gain) Loss, Net. During 2008, we entered into certain 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 as of March 31, 2009 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. The components of our commodity derivative (gain) loss, net were as follows (in thousands):

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	Year Ended December 31, 2009	2008
Change in unrealized (gains) losses on derivative contracts	$220,926	$(4,292)
Realized cash settlement (gains) losses	18,634	(900)
(Gain) loss on hedging ineffectiveness	22,655	(1,896)
Total	$262,215	$(7,088)

With respect to our open derivative contracts at December 31, 2009 and 2008, the futures curve of forecasted commodity prices ("forward price curve") for crude oil generally exceeded the forward price curves that were in effect when 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 2009 resulted in a $220.9 million loss in such net liability position due to the significant upward shift in the forward price curve for NYMEX crude oil from January 1 to December 31, 2009. The change in unrealized (gains) losses on derivative contracts in 2008, on the other hand, resulted in a $4.3 million gain due to the downward shift in the same forward price curve from January 1 to December 31, 2008. Also contributing to the large unrealized (gain) loss on derivative contracts in 2009 as compared to the prior year was the fact that we averaged 20.0 MMBbls of crude oil hedged during the year ended December 31, 2009, while we only averaged 6.8 MMBbls of crude oil hedged during the year ended December 31, 2008.

Income Tax Expense (Benefit). Income tax benefit totaled $56.0 million during 2009, versus $156.7 million of income tax expense in 2008. Our effective income tax rate decreased from 38.3% for 2008 to 34.4% for 2009. Our pre-tax book loss when taken together with our permanent items resulted in a decrease in our overall effective tax rate. This decrease, however, was partially offset by an increase in our effective tax rate caused by a change in our drilling activity in various states. Our effective tax rates for 2009 and 2008 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, 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 stockholders' equity. At December 31, 2009, our debt to total capitalization ratio was 25.6%, we had $12.0 million of cash on hand and $2,270.1 million of stockholders' equity. In 2010, we generated $997.3 million of cash provided by operating activities, an increase of $543.5 million from 2009. Cash provided by operating activities increased primarily due to higher crude oil production volumes and higher average sales prices for both oil and natural gas in 2010. These positive factors were partially offset by lower gas production volumes in 2010, as well as increased production taxes, lease operating expenses and general and administrative expenses during 2010 as compared to 2009. Cash flows from operating activities were used to finance $739.0 million of drilling and development expenditures and $184.7 million of cash acquisition capital expenditures paid in 2010, the premium of $47.5 million for the induced conversion of our convertible perpetual preferred stock and $20.5 million in debt issuance costs. The following chart details our exploration and development expenditures incurred by region during 2010 (in thousands):

	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 498,533	$ 15,604	$ 514,137	63 %
Permian Basin	203,138	10,489	213,627	26 %
Mid-Continent	56,582	1,573	58,155	7 %
Gulf Coast	20,972	5,115	26,087	3 %
Michigan	10,794	65	10,859	1 %
Total incurred	790,019	32,846	822,865	100 %

Increase in accrued capital expenditures	(54,791)	-	(54,791)
Total paid	$ 735,228	$ 32,846	$ 768,074

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We continually evaluate our capital needs and compare them to our capital resources. Our current 2011 capital budget is $1,350.0 million. This represents a 38% increase from the $978.3 million incurred on exploration, development and acreage expenditures during 2010. Acreage acquisition costs increased substantially during 2010 to $155.5 million. While these costs were not included in our 2010 capital budget, we anticipate investing $110.0 million in acreage acquisitions during 2011 and have therefore included this category in our 2011 capital budget. We expect to fund substantially all of our 2011 capital budget with net cash provided by our operating activities. We have increased our 2011 capital budget from our level of actual exploration and development expenditures incurred in 2010 in response to higher oil prices experienced throughout 2010 and continuing into the first part of 2011, as well as in response to higher crude oil production volumes. Although we have only budgeted $110.0 million for property acquisitions in 2011, 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 $1,350.0 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, or agreements with industry partners. Our level of exploration and development 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, dividend distributions 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, 2010 had a borrowing base of $1.1 billion with $899.6 million of available borrowing capacity, which was net of $200.0 million in borrowings and $0.4 million in letters of credit outstanding. The credit agreement provides for interest only payments until October 2015, when the agreement expires and all outstanding borrowings are due.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the 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. Whiting Oil and Gas may, throughout the term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect at any given time. A portion of the revolving credit agreement 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, 2010, $49.6 million was available for additional letters of credit under the agreement.

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. 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, 2010.

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.

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Senior Subordinated Notes. In September 2010, we issued at par $350.0 million of 6.5% Senior Subordinated Notes due October 2018. We used the net proceeds from this issuance to repay a portion of the debt under our credit agreement, which was borrowed to redeem our 2012 and 2013 notes. 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, 2010. 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.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The table below does not include our Production Participation Plan liability of $112.9 million (which amount comprises both the long and short-term portions of this obligation) as of December 31, 2010, 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, 2010 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)	$ 800,000	$ -	$ -	$ 450,000	$ 350,000
Cash interest expense on debt (b)	254,360	45,280	90,560	55,957	62,563
Derivative contract liability fair value (c)	164,631	69,375	95,256	-	-
Asset retirement obligations (d)	83,083	6,089	5,802	5,452	65,740
Tax sharing liability (e)	22,492	1,786	3,187	17,519	-
Purchase obligations (f)	125,550	45,639	70,350	9,561	-
	106,603	38,268	57,123	11,212	-

Drilling rig contracts (g)					
Operating leases (h)	9,312	3,596	5,716	-	-
Total	$ 1,566,031	$ 210,033	$ 327,994	$ 549,701	$ 478,303

(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, 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 instrument due date and is estimated at a fixed interest rate of 2.5%.

(c) The above derivative obligation at December 31, 2010 consists of a $158.4 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, 2010 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, 2010 also consists of a $6.2 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.

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(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 two take-or-pay purchase agreements, both expiring in December 2014, 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 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 a ship-or-pay agreement expiring in June 2013, whereby we have committed to transport a minimum daily volume of CO2 via the Transpetco pipeline 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.

(g) We currently have six drilling rigs under long-term contract, of which one drilling rig expires in 2011, two in 2012, one in 2013 and two in 2014. All of these rigs are operating in the Rocky Mountains region. As of December 31, 2010, early termination of the remaining contracts would require termination penalties of $66.0 million, which would be in lieu of paying the remaining drilling commitments of $106.6 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 116,100 square feet of administrative office space in Denver, Colorado under an operating lease arrangement expiring in 2013, and an additional 46,700 square feet of office space in Midland, Texas expiring in 2012.

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.

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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.

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, 2010. 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.

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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. 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 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, 2010 would have decreased net income before taxes by $12.3 million in 2010.

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. The oil and natural gas reference prices of these commodity derivative contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices we receive.

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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 actual results, changes in market conditions 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 the deferred tax assets will not be realized, the tax asset would be 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).

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. Prior to 2007, we recorded contingent income tax liabilities to the extent they were probable and could be reasonably estimated.

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.

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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

While costs in 2009 remained consistent with 2008, we experienced increased costs during 2010 due to increased demand for oil field products and services. The oil and gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry 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.

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.

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These risks and uncertainties include, but are not limited to: declines in oil or natural gas prices; impacts of the global recession and tight credit markets; 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 CO2; 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; 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; federal and state initiatives relating to hydraulic fracturing; 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 2010 production, our income before income taxes for 2010 would have moved up or down $19.0 million for each $1.00 per Bbl change in oil prices and $2.7 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.

Our outstanding hedges as of February 22, 2011 are summarized below:

Whiting Petroleum Corporation

Commodity	Period	Monthly Volume (Bbl)	Weighted Average NYMEX Floor/Ceiling
Crude Oil	01/2011 to 03/2011	895,000	$60.87/$96.65
Crude Oil	04/2011 to 06/2011	895,000	$60.87/$97.87
Crude Oil	07/2011 to 09/2011	895,000	$60.87/$97.87
Crude Oil	10/2011 to 12/2011	895,000	$60.87/$97.87
Crude Oil	01/2012 to 03/2012	550,000	$55.03/$99.03
Crude Oil	04/2012 to 06/2012	550,000	$55.03/$99.03
Crude Oil	07/2012 to 09/2012	550,000	$55.03/$99.03
Crude Oil	10/2012 to 12/2012	550,000	$55.03/$99.03
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 910 MBbls of crude oil and 3,391 MMcf of natural gas from 2011 through 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	01/2011 to 03/2011	40,978	$74.00/$139.68
Crude Oil	04/2011 to 06/2011	40,066	$74.00/$140.08
Crude Oil	07/2011 to 09/2011	39,170	$74.00/$140.15
Crude Oil	10/2011 to 12/2011	38,242	$74.00/$140.75
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	01/2011 to 03/2011	157,600	$7.00/$17.40
Natural Gas	04/2011 to 06/2011	152,703	$6.00/$13.05
Natural Gas	07/2011 to 09/2011	148,163	$6.00/$13.65
Natural Gas	10/2011 to 12/2011	142,787	$7.00/$14.25
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 contracts listed in both tables above, a hypothetical $10.00 per Bbl change in the NYMEX forward curve as of December 31, 2010 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $9.4 million. For the natural gas contracts listed above, a hypothetical $1.00 per Mcf change in the NYMEX forward curve as of December 31, 2010 applied to the notional amounts would cause a change in our commodity derivative (gain) loss of $0.9 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 February 22, 2011 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	Weighted Average Price Per MMBtu
Natural Gas	01/2011 to 03/2011	777,960	$5.30
Natural Gas	04/2011 to 06/2011	778,914	$5.31
Natural Gas	07/2011 to 09/2011	772,460	$5.30
Natural Gas	10/2011 to 12/2011	772,460	$5.30
Natural Gas	01/2012 to 03/2012	577,127	$5.30
Natural Gas	04/2012 to 06/2012	461,460	$5.41
Natural Gas	07/2012 to 09/2012	465,794	$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

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Interest Rate Risk

Market risk is estimated as the change in fair value resulting from a hypothetical 100 basis point change in the interest rate on the outstanding balance under our credit agreement. Our credit agreement allows us to fix the interest rate for all or a portion of the principal balance for a period up to six months. To the extent that the interest rate is fixed, interest rate changes affect the instrument's fair market value but do not impact results of operations or cash flows. Conversely, for the portion of the credit agreement that has a floating interest rate, interest rate changes will not affect the fair market value but will impact future results of operations and cash flows. Changes in interest rates do not affect the amount of interest we pay on our fixed-rate Senior Subordinated Notes. At December 31, 2010, our outstanding principal balance under our credit agreement was $200.0 million, and the weighted average interest rate on the outstanding principal balance was 2.5%. At December 31, 2010, the carrying amount approximated fair market value. Assuming a constant debt level of $200.0 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 $2.0 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, 2010 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, 2010, 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, 2010 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, 2010, based on criteria established in Internal Control — Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission. The Company's management is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying Management's 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, 2010, 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, 2010 of the Company and our report dated February 24, 2011 expressed an unqualified opinion on those financial statements and financial statement schedule and included an explanatory paragraph regarding the Company’s adoption of new accounting guidance in the prior year.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 24, 2011

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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, 2010 and 2009, and the related consolidated statements of income, stockholders' equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2010. 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, 2010 and 2009, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2010, 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, 2010, 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 24, 2011 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 24, 2011

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

	December 31, 2010	December 31, 2009
ASSETS		
Current assets:		
Cash and cash equivalents	$18,952	$11,960
Accounts receivable trade, net	199,713	152,082
Prepaid expenses and other	14,878	11,983
Total current assets	233,543	176,025
Property and equipment:		
Oil and gas properties, successful efforts method:		
Proved properties	5,661,619	4,870,688
Unproved properties	226,336	100,706
Other property and equipment	98,092	100,833
Total property and equipment	5,986,047	5,072,227
Less accumulated depreciation, depletion and amortization	(1,630,824)	(1,274,121)
Total property and equipment, net	4,355,223	3,798,106
Debt issuance costs	34,226	24,672
Other long-term assets	25,785	30,739
TOTAL ASSETS	$4,648,777	$4,029,542
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities:		
Accounts payable trade	$35,016	$14,023
Accrued capital expenditures	84,789	29,998
Accrued liabilities and other	153,062	110,320
Revenues and royalties payable	82,124	46,327
Taxes payable	30,291	21,188
Derivative liabilities	69,375	49,551
Deferred income taxes	4,548	11,325
Total current liabilities	459,205	282,732
Long-term debt	800,000	779,585
Deferred income taxes	539,071	341,037
Derivative liabilities	95,256	137,621
Production Participation Plan liability	81,524	69,433
Asset retirement obligations	76,994	66,846
Deferred gain on sale	41,460	58,462
Other long-term liabilities	23,952	23,741
Total liabilities	2,117,462	1,759,457
Commitments and contingencies		
Stockholders' equity:		
Preferred stock, $0.001 par value, 5,000,000 shares authorized; 6.25% convertible perpetual preferred stock, 172,500 shares issued and outstanding as of December 31, 2010 and 3,450,000 shares issued and outstanding as of December 31, 2009, aggregate liquidation preference of $17,250,000 at December 31, 2010	-	3

Common stock, $0.001 par value, 175,000,000 shares authorized; 117,967,876 issued and 117,098,506 outstanding as of December 31, 2010, 102,727,276 issued and 101,690,748 outstanding as of December 31, 2009 (1)	59	51
Additional paid-in capital	1,549,822	1,546,635
Accumulated other comprehensive income	5,768	20,413
Retained earnings	975,666	702,983
Total stockholders' equity	2,531,315	2,270,085
TOTAL LIABILITIES AND STOCKHOLDERS' EQUITY	$4,648,777	$4,029,542

(1) All common share amounts (except par value and par value per share amounts) have been retroactively restated for all periods presented to reflect the Company's two-for-one stock split described in Notes 8 and 13 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, 2010	2009	2008
REVENUES AND OTHER INCOME:			
Oil and natural gas sales	$1,475,288	$917,541	$1,316,480
Gain (loss) on hedging activities	23,198	38,776	(107,555)
Amortization of deferred gain on sale	15,613	16,596	12,143
Gain on sale of properties	1,388	5,947	-
Interest income and other	612	500	1,051
Total revenues and other income	1,516,099	979,360	1,222,119
COSTS AND EXPENSES:			
Lease operating	268,348	237,270	241,248
Production taxes	103,880	64,672	87,548
Depreciation, depletion and amortization	393,897	394,792	277,448
Exploration and impairment	59,371	73,014	55,257
General and administrative	64,694	42,357	61,684
Interest expense	59,078	64,608	65,078
Loss on early extinguishment of debt	6,235	-	-
Change in Production Participation Plan liability	12,091	3,267	32,124
Commodity derivative (gain) loss, net	7,062	262,215	(7,088)
Total costs and expenses	974,656	1,142,195	813,299
INCOME (LOSS) BEFORE INCOME TAXES	541,443	(162,835)	408,820
INCOME TAX EXPENSE (BENEFIT):			
Current	4,979	236	2,361
Deferred	199,811	(56,189)	154,316
Total income tax expense (benefit)	204,790	(55,953)	156,677
NET INCOME (LOSS)	336,653	(106,882)	252,143
Preferred stock dividends and inducement premium	(63,970)	(10,302)	-
NET INCOME (LOSS) AVAILABLE TO COMMON SHAREHOLDERS	$272,683	$(117,184)	$252,143
EARNINGS (LOSS) PER COMMON SHARE (1):			
Basic	$2.57	$(1.18)	$2.98
Diluted	$2.55	$(1.18)	$2.97
WEIGHTED AVERAGE SHARES OUTSTANDING (1):			
Basic	106,338	100,088	84,620
Diluted	107,846	100,088	84,895

(1) All share and per share amounts have been retroactively restated for all periods presented to reflect the Company's two-for-one stock split described in Notes 8 and 13 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, 2010	2009	2008
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$336,653	$(106,882)	$252,143
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depreciation, depletion and amortization	393,897	394,792	277,448
Deferred income tax expense (benefit)	199,811	(56,189)	154,316
Amortization of debt issuance costs and debt discount	10,592	11,026	6,068
Stock-based compensation	8,871	7,650	4,177
Amortization of deferred gain on sale	(15,613)	(16,596)	(12,143)
Gain on sale of properties	(1,388)	(5,947)	-
Undeveloped leasehold and oil and gas property impairments	26,525	26,139	25,955
Exploratory dry hole costs	3,819	18,212	3,513
Loss on early extinguishment of debt	6,235	-	-
Change in Production Participation Plan liability	12,091	3,267	32,124
Unrealized (gain) loss on derivative contracts	(40,736)	218,255	(6,189)
Other non-current	(4,013)	955	(18,825)
Changes in current assets and liabilities:			
Accounts receivable trade	(47,631)	(27,336)	(12,396)
Prepaid expenses and other	(3,387)	30,024	(29,136)
Accounts payable trade and accrued liabilities	66,663	(55,917)	75,227
Revenues and royalties payable	35,797	11,221	8,901
Taxes payable	9,103	1,150	5,359
Net cash provided by operating activities	997,289	453,824	766,542
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash acquisition capital expenditures	(184,729)	(97,920)	(438,759)
Drilling and development capital expenditures	(739,047)	(506,089)	(895,607)
Proceeds from sale of oil and gas properties	9,202	80,462	1,450
Proceeds from sale of marketable securities	-	-	764
Net proceeds from sale of 11,677,500 units in Whiting USA Trust I	-	-	193,692
Net cash used in investing activities	(914,574)	(523,547)	(1,138,460)
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)	-	-
Preferred stock dividends paid	(16,441)	(10,302)	-

Long-term borrowings under credit agreement	1,150,000	490,000	1,105,000
Repayments of long-term borrowings under credit agreement	(1,110,000)	(950,000)	(735,000)
Repayments to Alliant Energy Corporation	(1,615)	(2,701)	(3,236)
Debt issuance costs	(20,471)	(23,141)	-
Restricted stock used for tax withholdings	(5,679)	(662)	-
Net cash (used in) provided by financing activities	(75,723)	72,059	366,764

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,		
	2010	2009	2008
NET CHANGE IN CASH AND CASH EQUIVALENTS	$6,992	$2,336	$(5,154)
CASH AND CASH EQUIVALENTS:			
Beginning of period	11,960	9,624	14,778
End of period	$18,952	$11,960	$9,624
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid (refunded) for income taxes	$6,181	$(1,408)	$1,667
Cash paid for interest, net of amounts capitalized	$46,332	$52,754	$60,578
NONCASH INVESTING ACTIVITIES:			
Accrued capital expenditures	$84,789	$29,998	$84,960
NONCASH FINANCING ACTIVITIES:			
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 STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(In thousands)

	Preferred Stock Shares	Preferred Stock Amount	Common Stock (1) Shares	Common Stock (1) Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Retained Earnings	Total Stockholders' Equity	Comprehensive Income (Loss)
BALANCES-January 1, 2008	-	-	84,960	42	968,876	(46,116)	568,024	1,490,826	
Net income	-	-	-	-	-	-	252,143	252,143	$252,143
Change in derivative fair values, net of taxes of $1,812	-	-	-	-	-	(3,072)	-	(3,072)	(3,072)
Realized loss on settled derivative contracts, net of taxes of $39,903	-	-	-	-	-	67,652	-	67,652	67,652
Ineffectiveness gain on hedging activities, net of taxes of $703	-	-	-	-	-	(1,193)	-	(1,193)	(1,193)
Total comprehensive income									$315,530
Restricted stock issued	-	-	278	1	-	-	-	1	
Restricted stock forfeited	-	-	(14)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(60)	-	(1,743)	-	-	(1,743)	
Stock-based compensation	-	-	-	-	4,177	-	-	4,177	
BALANCES-December 31, 2008	-	-	85,164	43	971,310	17,271	820,167	1,808,791	
Net loss	-	-	-	-	-	-	(106,882)	(106,882)	$(106,882)
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	3,450	3	-	-	334,109	-	-	334,112	

preferred stock									
Issuance of stock, secondary offering	-	-	16,900	8	234,745	-	-	234,753	
Restricted stock issued	-	-	728	-	-	-	-	-	
Restricted stock forfeited	-	-	(10)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(54)	-	(662)	-	-	(662)	
Tax effect from restricted stock vesting	-	-	-	-	(517)	-	-	(517)	
Stock-based compensation	-	-	-	-	7,650	-	-	7,650	
Preferred dividends paid	-	-	-	-	-	-	(10,302)	(10,302)	
BALANCES-December 31, 2009	3,450	3	102,728	51	1,546,635	20,413	702,983	2,270,085	
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)	
Restricted stock issued	-	-	325	-	-	-	-	-	
Restricted stock forfeited	-	-	(27)	-	-	-	-	-	
Restricted stock used for tax withholdings	-	-	(156)	-	(5,679)	-	-	(5,679)	
Stock-based compensation	-	-	-	-	8,871	-	-	8,871	
Preferred dividends paid	-	-	-	-	-	-	(16,441)	(16,441)	
BALANCES-December 31, 2010	173	$-	117,968	$59	$1,549,822	$5,768	$975,666	$2,531,315	

(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 described in Notes 8 and 13 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 Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan 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, all of which are wholly-owned, 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, 2010 and 2009, the Company had an allowance for doubtful accounts of $0.4 million and $1.3 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.

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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 unit-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.

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 in income.

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 2010, 2009 and 2008, the Company capitalized interest of $2.9 million, $3.4 million and $3.1 million, respectively.

Unproved. Unproved properties consist of costs incurred to acquire undeveloped leases as well as costs to acquire unproved reserves. Undeveloped lease costs and unproved reserve acquisition costs are capitalized, and individually insignificant unproved properties are amortized on a composite basis, based on past success, 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. Unproved property costs related to successful exploratory drilling 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 development 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.

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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.

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, the effective portion of any changes in fair value is 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 is recognized in commodity derivative (gain) loss, net as it occurs. 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.

For derivatives designated as hedges of the fair value of recognized assets, liabilities or firm commitments, changes in the fair values of both the hedged item and the related derivative are recognized immediately in net income with an offsetting effect included in the basis of the hedged item. The net effect is to report in earnings the extent to which the hedge is not effective, if any, in achieving offsetting changes in fair value.

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, 2010 and 2009, the Company was in a net under (over) produced imbalance position of 12,666 Mcf and (12,889) 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 income tax positions must meet a more-likely-than-not recognition threshold to be recognized, and any potential accrued interest and penalties related to unrecognized tax benefits are recognized within income tax expense.

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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.

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. 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 the Company's total oil and gas production revenue. During 2009, sales to Shell Western E&P, Inc., Plains Marketing LP and EOG Resources, Inc. accounted for 18%, 15% and 13%, respectively, of the Company's total oil and gas production revenue. During 2008, sales to Plains Marketing LP and Valero Energy Corporation accounted for 15% and 14%, respectively, of the Company's total oil and gas production revenue. 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, 2010, outstanding derivative contracts with JP Morgan Chase Bank, N.A., KeyBank National Association, and Wells Fargo Bank, N.A. represent 24%, 23% and 12%, 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.

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

Adopted and Recently Issued Accounting Pronouncements—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 is effective for fiscal years beginning after December 15, 2010. 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 January 2010, the FASB issued Accounting Standards Update No. 2010-06, Improving Disclosures about Fair Value Measurements ("ASU 2010-06"), which provides amendments to FASB ASC Topic 820, Fair Value Measurements and Disclosures. The objective of ASU 2010-06 is to provide more robust disclosures about (i) the different classes of assets and liabilities measured at fair value, (ii) the valuation techniques and inputs used, (iii) the activity in Level 3 fair value measurements, and (iv) significant transfers between Levels 1, 2 and 3. ASU 2010-06 was effective for fiscal years and interim periods beginning after December 15, 2009, except for the activity in Level 3 measurement disclosures which is effective January 1, 2011. The Company adopted ASU 2010-06 effective January 1, 2010, which did not have an impact on its consolidated financial statements, other than additional disclosures.

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 and 2010 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 and 2010 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.

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 and 2010 reserve quantities using the 12-month average price, (ii) prepared its reserve estimates as of December 31, 2009 and 2010 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.

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2. ACQUISITIONS AND DIVESTITURES

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, and substantially all of the purchase price was allocated to the properties and acreage acquired. Disclosures of pro forma revenues and net income for this acquisition 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, with a purchase price of $38.7 million and an effective date of October 1, 2009. The Company completed the second acquisition of additional royalty and overriding royalty interests in December 2009, with a purchase price of $27.4 million and an effective date of November 1, 2009. 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.

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2008 Acquisition

In May 2008, Whiting acquired interests in 31 producing gas wells, development acreage and gas gathering and processing facilities on approximately 22,000 gross (11,500 net) acres in the Flat Rock field in Uintah County, Utah for an aggregate unadjusted purchase price of $365.0 million.

This acquisition was recorded using the purchase method of accounting. The table below summarizes the allocation of the $359.4 million adjusted purchase price, based on the acquisition date fair value of the assets acquired and the liabilities assumed (in thousands).

	Flat Rock
Purchase price	$359,380
Allocation of purchase price:	
Proved properties	$251,895
Unproved properties	79,498
Gas gathering and processing facilities	35,736
Liabilities assumed	(7,749)
Total	$359,380

2008 Divestiture

On April 30, 2008, the Company completed an initial public offering of units of beneficial interest in Whiting USA Trust I (the "Trust"), selling 11,677,500 Trust units at $20.00 per Trust unit, providing net proceeds of $193.7 million after underwriters' fees, offering expenses and post-close adjustments. The Company used the net offering proceeds to repay a portion of the debt outstanding under its credit agreement. The net proceeds from the sale of Trust units to the public resulted in a deferred gain on sale of $100.2 million. Immediately prior to the closing of the offering, Whiting conveyed a term net profits interest in certain of its oil and gas properties to the Trust in exchange for 13,863,889 Trust units. The Company has retained 15.8%, or 2,186,389 Trust units, of the total Trust units issued and outstanding.

The net profits interest entitles the Trust to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate at the time when 9.11 MMBOE have been produced and sold from the underlying properties. This is the equivalent of 8.2 MMBOE in respect of the Trust's right to receive 90% of the net proceeds from such production pursuant to the net profits interest.

3. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2010 and 2009 (in thousands):

	December 31,	
	2010	2009
Credit agreement	$200,000	$160,000
6.5% Senior Subordinated Notes due 2018	350,000	-
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,147	-	218,853
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $268	-	150,732

Total debt	$800,000	$779,585

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Credit Agreement—In October 2010, Whiting Oil and Gas Corporation (“Whiting Oil and Gas”), the Company’s wholly-owned subsidiary, entered into a Fifth Amended and Restated Credit Agreement with a syndicate of banks, and this credit facility replaced Whiting Oil and Gas’ existing credit agreement. This amended credit agreement extended the principal repayment date from April 2012 to October 2015 and maintained the borrowing base of $1.1 billion. As of December 31, 2010, there was $899.6 million of available borrowing capacity under this facility, which is net of $200.0 million in borrowings and $0.4 million in letters of credit outstanding. The credit agreement provides for interest only payments until October 2015, when the agreement expires and all outstanding borrowings are due.

The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of the Company’s proved reserves that have been mortgaged to 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, 2010, $49.6 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. The Company also incurs commitment fees of 0.50% 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, 2010, the weighted average interest rate on the outstanding principal balance under the credit agreement was 2.5%.

Ratio of Outstanding Borrowings to Borrowing Base	Applicable Margin for Base Rate Loans	Applicable Margin for Eurodollar Loans
Less than 0.25 to 1.0	0.75%	1.75%
Greater than or equal to 0.25 to 1.0 but less than 0.50 to 1.0	1.00%	2.00%
Greater than or equal to 0.50 to 1.0 but less than 0.75 to 1.0	1.25%	2.25%
Greater than or equal to 0.75 to 1.0 but less than 0.90 to 1.0	1.50%	2.50%
Greater than or equal to 0.90 to 1.0	1.75%	2.75%

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 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 the subsidiaries. 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, 2010.

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.

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Senior Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due 2014. The estimated fair value of these notes was $257.5 million as of December 31, 2010, 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 all of its $150.0 million aggregate principal amount of 7.25% Senior Subordinated Notes due 2012 and all of its $220.0 million aggregate principal amount of 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 under its credit agreement, which was borrowed to redeem its 2012 and 2013 notes. The estimated fair value of these notes was $348.3 million as of December 31, 2010, 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, 2010 and 2009 were $6.1 million and $10.3 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, 2010 and 2009 (in thousands):

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	Year Ended December 31, 2010	2009
Beginning asset retirement obligation at January 1	$77,186	$54,348
Additional liability incurred	3,518	538
Revisions in estimated cash flows	5,548	19,793
Accretion expense	7,223	7,126
Obligations on sold properties	(5,542)	(93)
Liabilities settled	(4,850)	(4,526)
Ending asset retirement obligation at December 31	$83,083	$77,186

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 Trust derivatives, entered into to hedge forecasted crude oil and natural gas production revenues, as of February 22, 2011.

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 2011	10,855,039	436,510	$61.01 - $98.02	$6.50 - $14.62
Jan – Dec 2012	6,705,091	384,002	$55.40 - $99.70	$6.50 - $14.27
Jan – Nov 2013	3,090,000	-	$47.64 - $89.90	n/a
Total	20,650,130	820,512		

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 (as further explained in the note on Acquisitions and Divestitures), 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			
			Weighted Average	
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jan – Dec 2011	115,039	436,510	$74.00 - $140.15	$6.50 - $14.62
Jan – Dec 2012	105,091	384,002	$74.00 - $141.72	$6.50 - $14.27
Total	220,130	820,512		

The 75.8% portion of Trust derivative contracts for 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			
			Weighted Average	
	Contracted Volumes		NYMEX Price Collar Ranges	
Period	Crude Oil (Bbl)	Natural Gas (Mcf)	Crude Oil (per Bbl)	Natural Gas (per Mcf)
Jan – Dec 2011	360,329	1,367,249	$74.00 - $140.15	$6.50 - $14.62
Jan – Dec 2012	329,171	1,202,785	$74.00 - $141.72	$6.50 - $14.27
Total	689,500	2,570,034		

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, while the Company's remaining commodity derivative contracts were not designated as hedges, with gains and losses from changes in fair value recognized immediately in earnings. 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 as of March 31, 2009 and has elected to discontinue hedge accounting prospectively. As a result, subsequent to March 31, 2009 the Company recognizes all gains and losses from prospective changes in commodity derivative fair values immediately in earnings rather than deferring any such amounts in accumulated other comprehensive income.

At March 31, 2009, accumulated other comprehensive income consisted of $59.8 million ($36.5 million net of tax) of unrealized gains, representing the mark-to-market value of the Company's open commodity contracts designated as cash flow hedges as of that date, less any ineffectiveness recognized. As a result of discontinuing hedge accounting on April 1, 2009, such mark-to-market values at March 31, 2009 are frozen in accumulated other comprehensive income as of the de-designation date and reclassified into earnings as the original hedged transactions affect income. During the years ended December 31, 2010 and 2009, $23.2 million ($14.6 million net of tax) and $25.3 million ($16.0 million net of tax), respectively, of derivative gains relating to de-designated commodity hedges were reclassified from accumulated other comprehensive income into earnings.

As of December 31, 2010, accumulated other comprehensive income amounted to $9.1 million ($5.8 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 $5.5 million related to de-designated commodity hedges.

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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 sales" exclusion. The following tables summarize the location and fair value amounts of all derivative instruments in the consolidated balance sheets (in thousands).

Not Designated as ASC 815 Hedges	Balance Sheet Classification	Fair Value December 31, 2010	Fair Value December 31, 2009
Derivative assets			
Commodity contracts	Prepaid expenses and other	$4,231	$4,723
Commodity contracts	Other long-term assets	3,961	8,473
Total derivative assets		8,192	13,196
Derivative liabilities			
Commodity contracts	Current derivative liabilities	$69,375	$49,551
Commodity contracts	Non-current derivative liabilities	95,256	137,621
Total derivative liabilities		$164,631	$187,172

Commodity derivative contracts. The following tables summarize the effects of commodity derivatives instruments on the consolidated statements of income for the twelve months ended December 31, 2010 and 2009 (in thousands).

ASC 815 Cash Flow Hedging Relationships	Location of Gain Not Recognized in Income	Gain Recognized in OCI (Effective Portion) Year Ended December 31, 2010	2009
Commodity contracts	Other comprehensive income	$-	$21,147

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Gain Reclassified from OCI into Income (Effective Portion) Year Ended December 31, 2010	2009
Commodity contracts	Gain (loss) on hedging activities	$23,198	$38,776

ASC 815 Cash Flow Hedging Relationships	Income Statement Classification	Loss Recognized in Income (Ineffective Portion) Year Ended December 31, 2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$-	$22,655

Not Designated as ASC 815 Hedges	Income Statement Classification	Loss Recognized in Income Year Ended December 31, 2010	2009
Commodity contracts	Commodity derivative (gain) loss, net	$7,062	$239,560

Contingent features in derivative instruments. None of the Company's derivative instruments contain credit-risk-related contingent features. Counterparties to the Company's derivative contracts are high credit-quality financial institutions that are lenders under Whiting's credit agreement. Whiting 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 end 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, 2010 and 2009, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Level 1	Level 2	Level 3	Total Fair Value December 31, 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

	Level 1	Level 2	Level 3	Total Fair Value December 31, 2009
Financial Assets				
Commodity derivatives - current	$-	$4,723	$-	$4,723
Commodity derivatives - non-current	-	8,473	-	8,473
Total financial assets	$-	$13,196	$-	$13,196
Financial Liabilities				

Commodity derivatives - current	$-	$49,551	$-	$49,551
Commodity derivatives - non-current	-	137,621	-	137,621
Total financial liabilities	$-	$187,172	$-	$187,172

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

Commodity Derivative Instruments. Commodity derivative instruments consist primarily of costless collars for crude oil and natural gas. The Company's costless collars are valued using industry-standard models, which are based on a market approach. These models 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. Substantially all of 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.

Non-Recurring Fair Value Measurements. The Company applies the provisions of the fair value measurement standard to its non-recurring, non-financial measurements including business combinations, proved oil and gas property impairments and asset retirement obligations. These assets and liabilities are not measured at fair value on an ongoing basis but are subject to fair value adjustments only in certain circumstances. The following tables present information about the Company's non-financial assets and liabilities measured at fair value on a non-recurring basis as of December 31, 2010 and 2009, and indicate the fair value hierarchy of the valuation techniques utilized by the Company to determine such fair values (in thousands):

	Net Carrying Value as of December 31, 2010	Fair Value Measurements Using			Loss (Before Tax) Year Ended December 31, 2010
		Level 1	Level 2	Level 3	
Business combinations(1)(2)	$22,267	$-	$ -	$ 22,763	$-
Asset retirement obligations (3)	3,586	-	-	3,518	-
Total non-recurring assets at fair value	$25,853	$-	$ -	$ 26,281	$

	Net Carrying Value as of December 31, 2009	Fair Value Measurements Using			Loss (Before Tax) Year Ended December 31, 2009
		Level 1	Level 2	Level 3	
Business combinations (2)	$65,697	$-	$ -	$ 66,120	$-
Proved property impairments (2)	7,849	-	-	8,218	9,420
Asset retirement obligations (3)	519	-	-	538	-

Total non-recurring assets at fair value	$74,065	$-	$ -	$ 74,876	$9,420

(1) The business combinations in 2010 relate to the acquisition of various producing properties in the Rocky Mountain and Gulf Coast Regions and North Ward Estes field.
(2) The net carrying values as of December 31, 2010 and 2009 do not equal our fair value measurement due to the subsequent recognition of depletion expense.
(3) The net carrying values as of December 31, 2010 and 2009 do not equal our fair value measurements at the time such liabilities are incurred due to the subsequent recognition of accretion expense.

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

Business Combinations. The Company primarily values business combinations using the present value of estimated future cash flows, which are based on an income approach, discounted at a rate that reflects market participant assumptions based on the risk of the asset acquired. Given the unobservable nature of the inputs, business combinations are deemed to use Level 3 inputs.

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.

Asset Retirement Obligations. The Company estimates the fair value of asset retirement obligations at the point they are incurred by calculating the present value of estimated future plug and abandonment costs. Such present value calculations use internally developed cash flow models, which are based on an income approach, and include various assumptions such as estimated amounts and timing of abandonment cash flows, the Company’s credit-adjusted risk-free rate and future inflation rates. Given the unobservable nature of most of these inputs, the initial measurement of asset retirement obligation liabilities is deemed to use Level 3 inputs.

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, 2010, 2009 and 2008 amounted to $27.7 million, $15.8 million and $33.5 million, respectively, charged to general and administrative expense and $3.7 million, $2.4 million and $5.2 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, 2010, the Company used three-year average historical NYMEX prices of $80.34 for crude oil and $5.69 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, 2010, 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 $162.2 million. This amount includes $13.7 million attributable to proved undeveloped oil and gas properties and $31.4 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2011. 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.

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

	Year Ended December 31, 2010	2009
Beginning long-term Production Participation Plan liability	$69,433	$66,166
Change in liability for accretion, vesting, changes in estimates and new Plan year activity	43,486	21,472
Cash payments accrued as compensation expense and reflected as a current payable	(31,395)	(18,205)
Ending long-term Production Participation Plan liability	$81,524	$69,433

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):

	Year Ended December 31, 2010	2009	2008
General and administrative expense	$10,676	$2,842	$27,852
Exploration expense	1,415	425	4,272
Total	$12,091	$3,267	$32,124

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 2010, 2009 and 2008 were $3.6 million, $3.7 million and $3.0 million, respectively. Employees vest in employer contributions at 20% per year of completed service.

8. STOCKHOLDERS' EQUITY

Common Stock—In May 2010, Whiting's stockholders approved an amendment to the Company's Amended and Restated Certificate of Incorporation to increase the number of authorized shares of common stock from 75,000,000 shares to 175,000,000 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 have been retroactively adjusted to reflect the stock split for all periods presented. 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.

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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 and providing net proceeds of $334.1 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.

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 initial 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.

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 2,978,776 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, 2010, 1,789,693 shares of common stock remained available for grant under the Plan.

For the years ended December 31, 2010, 2009 and 2008, total stock compensation expense recognized for restricted share awards and stock options was $8.9 million, $7.7 million and $4.2 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.

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In January 2010, February 2009 and February 2008, 180,898 shares, 419,298 shares and 149,084 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:

	2010	2009	2008
Number of simulations	65,000	100,000	100,000
Expected volatility	75.9%	70.0%	36.3%
Risk-free rate	1.40%	1.33%	2.24%

The grant date fair value of the market-based restricted stock as determined by the Monte Carlo valuation model was $22.99 per share in February 2010, $3.46 per share in February 2009 and $11.81 per share in February 2008.

The following table shows a summary of the Company's nonvested restricted stock as of December 31, 2008, 2009 and 2010 as well as activity during the years then ended (share and per share data, not presented in thousands):

	Number of Shares	Weighted Average Grant Date Fair Value
Restricted stock awards nonvested, January 1, 2008	479,312	$22.08
Granted	277,036	20.34
Vested	(224,768)	21.73
Forfeited	(14,052)	25.33
Restricted stock awards nonvested, December 31, 2008	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

As of December 31, 2010, there was $4.7 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, 2010, 2009 and 2008, the total fair value of restricted stock vested was $17.1 million, $2.5 million and $6.6 million, respectively.

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Stock Options. In January 2010 and February 2009, 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:

	Stock Options 2010	Stock Options 2009
Risk-free interest rate	2.75%	2.0%
Expected volatility	58.8%	58.1%
Expected term	6.0 yrs.	6.0 yrs.
Dividend yield	-	-

The grant date fair value of the stock options awarded, as determined by the Black-Scholes valuation model, was $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 and 2010 as well as activity during the years then ended (share and per share data, not 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	$ 12,400	8.3
Options vested and expected to vest at December 31, 2010	296,516	$ 16.78	$ 12,400	8.3

Options exercisable at December 31, 2010	80,404	$12.76	$3,686	8.1

Unrecognized compensation cost as of December 31, 2010 related to unvested stock option awards was $0.7 million, which is expected to be recognized over a period of 1.8 years.

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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.

9. INCOME TAXES

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

	Year Ended December 31,		
	2010	2009	2008
Current income tax expense (refund):			
Federal	$892	$741	$-
State	4,087	(505)	2,361
Total current income tax expense	4,979	236	2,361
Deferred income tax expense (benefit):			
Federal	188,386	(56,136)	142,393
State	11,425	(53)	11,923
Total deferred income tax expense (benefit)	199,811	(56,189)	154,316
Total	$204,790	$(55,953)	$156,677

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,		
	2010	2009	2008
U.S. statutory income tax expense (benefit)	$189,505	$(56,992)	$143,087
State income taxes, net of federal benefit	14,051	(1,228)	13,458
Statutory depletion	(632)	(394)	(583)
Enacted changes in state tax laws	-	711	-
Permanent items	1,071	1,482	715
Other	795	468	-
Total	$204,790	$(55,953)	$156,677

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The principal components of the Company's deferred income tax assets and liabilities at December 31, 2010 and 2009 were as follows (in thousands):

	Year Ended December 31, 2010	2009
Deferred income tax assets:		
Net operating loss carryforward	$121,503	$126,934
Derivative instruments	77,966	75,870
Production Participation Plan liability	30,164	25,690
Tax sharing liability	9,919	9,362
Asset retirement obligations	14,159	11,487
Underwriter fees	5,048	5,736
Restricted stock compensation	2,807	2,009
Enhanced oil recovery credit carryforwards	7,946	7,946
Alternative minimum tax credit carryforwards	11,285	10,393
Foreign tax credit carryforwards	1,230	1,230
Other	-	509
Total deferred income tax assets	282,027	277,166
Less valuation allowances	(1,230)	(1,230)
Net deferred income tax assets	280,797	275,936
Deferred income tax liabilities:		
Oil and gas properties	806,312	604,808
Trust distributions	18,093	23,490
Other	11	-
Total deferred income tax liabilities	824,416	628,298
Total net deferred income tax liabilities	$543,619	$352,362

As of December 31, 2010, we had federal net operating loss carryforwards of $344.4 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 in 2027, 2028 and 2029, and the state net operating losses will expire between 2012 and 2028.

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, 2010, 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.

The Company is subject to the alternative minimum tax ("AMT") principally due to its significant intangible drilling cost deductions. As of December 31, 2010, the Company had AMT credits totaling $11.3 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, 2010, the Company's foreign tax credit carryforwards totaled $1.2 million, which will expire between 2014 and 2016. As of December 31, 2010, 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,	
	2010	2009
Assets:		
Current deferred income taxes	$-	$-
Liabilities:		
Current deferred income taxes	4,548	11,325
Non-current deferred income taxes	539,071	341,037
Net deferred income tax liabilities	$543,619	$352,362

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

	Year Ended December 31,		
	2010	2009	2008
Beginning balance at January 1	$299	$299	$170
Increases related to tax position taken in the current year	-	-	129
Ending balance at December 31	$299	$299	$299

Included in the unrecognized tax benefit balance at December 31, 2010, 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, 2010, 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 2007 through 2010 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 2004 through 2006.

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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,		
	2010	2009	2008
Basic Earnings Per Share (1)			
Numerator:			
Net income (loss)	$336,653	$(106,882)	$252,143
Preferred stock dividends (2)	(63,069)	(11,247)	-
Net income (loss) available to common shareholders, basic	$273,584	$(118,129)	$252,143
Denominator:			
Weighted average shares outstanding, basic	106,338	100,088	84,620
Diluted Earnings Per Share(1)			
Numerator:			
Net income (loss) available to common shareholders, basic	$273,584	$(118,129)	$252,143
Preferred stock dividends	1,078	-	-
Adjusted net income (loss) available to common shareholders, diluted	$274,662	$(118,129)	$252,143
Denominator:			
Weighted average shares outstanding, basic	106,338	100,088	84,620
Restricted stock and stock options	714	-	275
Convertible perpetual preferred stock	794	-	-
Weighted average shares outstanding, diluted	107,846	100,088	84,895
Earnings (loss) per common share, basic	$2.57	$(1.18)	$2.98
Earnings (loss) per common share, diluted	$2.55	$(1.18)	$2.97

(1) All share and per share amounts have been retroactively restated for all periods presented to reflect the Company's two-for-one stock split described in Notes 8 and 13 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 were no accumulated dividends for the year ended December 31, 2008.

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, 2010 and 2009 (in thousands):

	December 31, 2010	December 31, 2009
Assets		
Unit distributions due from Trust (1)	$1,067	$1,023
Total	$1,067	$1,023
Liabilities		
Unit distributions payable to Trust (2)	$6,769	$6,485
Current portion of derivative liability due to Trust	3,208	3,580
Non-current derivative liability due to Trust	3,003	6,423
Total	$12,980	$16,488

(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, 2010, but which the Company has not yet distributed to the Trust as of December 31, 2010. Due to ongoing processing of Trust revenues and expenses after December 31, 2010, 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.

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For the year ended December 31, 2010, Whiting paid $38.2 million, net of state tax withholdings, in unit distributions to the Trust and received $5.9 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"), a holding company whose primary businesses are utility companies. 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 connection with Whiting's initial public offering in November 2003, the Company entered into a Tax Separation and Indemnification Agreement with Alliant Energy. Pursuant to this agreement, the Company and Alliant Energy made a tax election with the effect that the tax bases of Whiting's assets were increased to their deemed purchase price immediately prior to such initial public offering. Whiting has adjusted deferred taxes on its balance sheet to reflect the new tax bases of its assets. The additional bases are expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by Whiting.

Under this agreement, the Company has agreed to pay to Alliant Energy 90% of the future tax benefits the Company realizes annually as a result of this step-up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing the Company's actual taxes to the taxes that would have been owed by the Company had the increase in basis not occurred. In 2014, Whiting 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.

During 2010, 2009 and 2008, the Company made payments of $1.6 million, $2.7 million and $3.2 million, respectively, under this agreement and recognized interest expense of $1.5 million, $1.6 million and $1.3 million, respectively. The Company's estimated payment of $1.8 million to be made in 2011 under this agreement is reflected as a current liability at December 31, 2010, and the long-term portion of $20.7 million is included in other long-term liabilities.

The Tax Separation and Indemnification Agreement provides that if tax rates were to increase or decrease, the resulting tax benefit or detriment would cause a corresponding adjustment of the tax sharing liability. For purposes of this calculation, management has assumed that no such future changes will occur during the term of this agreement.

The Company periodically evaluates its estimates and assumptions as to future payments to be made under this agreement. If non-substantial changes (less than 10% on a present value basis) are made to the anticipated payments owed to Alliant Energy, a new effective interest rate is determined for this debt based on the carrying amount of the liability as of the modification date and based on the revised payment schedule. However, if there are substantial changes to the estimated payments owed under this agreement, then a gain or loss is recognized in the consolidated statements of income during the period in which the modification has been made.

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.

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12. COMMITMENTS AND CONTINGENCIES

Non-cancelable Leases—The Company leases 116,100 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through 2013 and an additional 46,700 square feet of office space in Midland, Texas until 2012. Rental expense for 2010, 2009 and 2008 amounted to \$3.4 million, \$3.0 million and \$2.2 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2010 are as follows (in thousands):

2011	\$3,596
2012	3,149
2013	2,567
Total	\$9,312

Purchase Contracts—The Company has two take-or-pay purchase agreements, both agreements expiring in December 2014, whereby the Company has committed to buy certain volumes of CO2 for a fixed fee subject to annual escalation. The purchase agreements are with different suppliers, and the CO2 is for use in the Company's enhanced recovery projects in its Postle field in Oklahoma and its North Ward Estes field in Texas. Under the terms of the agreements, the Company is obligated to purchase a minimum daily volume of CO2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the delivery was to have occurred. In addition, the Company has a ship-or-pay agreement expiring in June 2013, whereby it has committed to transport a minimum daily volume of CO2 via the Transpetco pipeline or else pay for any deficiencies at a price stipulated in the contract. The CO2 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, 2010, future commitments under these purchase agreements amounted to \$125.6 million through 2014.

Drilling Contracts—The Company currently has six drilling rigs under long-term contract, of which one drilling rig expires in 2011, two in 2012, one in 2013 and two in 2014. All of these rigs are operating in the Rocky Mountains region. As of December 31, 2010, early termination of the remaining contracts would require termination penalties of \$66.0 million, which would be in lieu of paying the remaining drilling commitments of \$106.6 million. Other drilling rigs working for the Company are not under long-term contracts or are under contracts that can 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 adverse 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:

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 have been retroactively adjusted to reflect the stock split for all periods presented. 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.

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Preferred stock dividend. On February 15, 2011, 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, 2011 to holders of record on March 1, 2011.

Acquisition. On February 15, 2011, the Company completed the acquisition of 6,000 net 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 and an effective date of February 1, 2011.

14. OIL AND GAS ACTIVITIES

The Company's oil and gas activities for 2010, 2009 and 2008 were entirely within the United States. Costs incurred in oil and gas producing activities were as follows (in thousands):

	Year Ended December 31,		
	2010	2009	2008
Development	$723,687	$436,721	$914,616
Proved property acquisition	22,763	78,800	294,056
Unproved property acquisition	155,472	12,872	98,841
Exploration	114,012	50,970	42,621
Total	$1,015,934	$579,363	$1,350,134

During 2010, 2009 and 2008, additions to oil and gas properties of $3.5 million, $0.5 million and $3.5 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,	
	2010	2009
Proved oil and gas properties	$5,661,619	$4,870,688
Unproved oil and gas properties	226,336	100,706
Accumulated depreciation, depletion and amortization	(1,612,553)	(1,258,141)
Oil and gas properties, net	$4,275,402	$3,713,253

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,		
	2010	2009	2008
Beginning balance at January 1	$-	$-	$525
Additions to capitalized exploratory well costs pending the determination of proved reserves	81,167	4,095	12,794
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(76,733)	(4,095)	(13,319)
Capitalized exploratory well costs charged to expense	-	-	-
Ending balance at December 31	$4,434	$-	$-

At December 31, 2010, the Company had no costs capitalized for exploratory wells in progress for a period of greater than one year after the completion of drilling.

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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, 2010. 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.

As of December 31, 2010, 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, 2008, 2009 and 2010, are as follows:

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBOE)
Balance—January 1, 2008	196,318	326,742	250,775
Extensions and discoveries	20,395	57,093	29,911
Sales of minerals in place	(3,919)	(14,277)	(6,299)
Purchases of minerals in place	513	90,329	15,568
Production	(12,448)	(30,419)	(17,518)
Revisions to previous estimates	(20,851)	(74,689)	(33,299)
Balance—December 31, 2008	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
Proved developed reserves:			
December 31, 2007	127,291	237,030	166,796
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
Proved undeveloped reserves:			
December 31, 2007	69,027	89,712	83,979
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

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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.

- 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.

Notable changes in proved reserves for the year ended December 31, 2008 included:

- Revisions to previous estimates. In 2008, negative revisions to previous estimates decreased proved reserve quantities by a net amount of 33.3 MMBOE. Included in these revisions were 39.0 MMBOE of negative adjustments caused by lower commodity prices at December 31, 2008 as compared to December 31, 2007, and 5.7 MMBOE of net positive adjustments primarily due to production performance and updated technical evaluations at Whiting's CO2 enhanced recovery projects.

- Extensions and discoveries. In 2008, total extensions and discoveries of 29.9 MMBOE resulted from successful drilling primarily in the Sanish, Sulphur Creek, and Parshall fields that extended the proved acreage in those fields.

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As discussed in Deferred Compensation, 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, 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, 2010 and 2009, respectively) to estimated future production. Future cash inflows as of December 31, 2008, however, were computed by applying prices at year end 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,		
	2010	2009	2008
Future cash flows	$19,314,032	$13,077,148	$8,558,178
Future production costs	(7,705,465)	(5,668,889)	(4,220,329)
Future development costs	(1,491,937)	(1,405,734)	(982,193)
Future income tax expense	(2,890,668)	(1,292,719)	(474,332)
Future net cash flows	7,225,962	4,709,806	2,881,324
10% annual discount for estimated timing of cash flows	(3,558,356)	(2,366,264)	(1,504,876)
Standardized measure of discounted future net cash flows	$3,667,606	$2,343,542	$1,376,448

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 $12.6 million in 2010, increased by $24.6 million in 2009 and increased by $345.9 million in 2008.

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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,		
	2010	2009	2008
Beginning of year	$2,343,542	$1,376,448	$4,011,665
Sale of oil and gas produced, net of production costs	(1,103,060)	(615,597)	(987,682)
Sales of minerals in place	(5,927)	(40,673)	(54,735)
Net changes in prices and production costs	1,881,636	1,233,813	(4,059,904)
Extensions, discoveries and improved recoveries	639,924	442,879	259,930
Previously estimated development costs incurred during the period	405,499	260,350	263,491
Changes in estimated future development costs	(434,549)	(452,480)	(154,569)
Purchases of mineral in place	14,597	53,372	135,288
Revisions of previous quantity estimates	378,552	319,028	(289,381)
Net change in income taxes	(686,962)	(371,243)	1,851,178
Accretion of discount	234,354	137,645	401,167
End of year	$3,667,606	$2,343,542	$1,376,448

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, 2010, 2009 and 2008 as follows:

	2010	2009	2008
Oil (per Bbl)	$70.32	$52.19	$38.51
Natural Gas (per Mcf)	$4.72	$3.77	$4.58

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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, 2010 and 2009 (in thousands, except per share data):

	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
	Three Months Ended			
	March 31, 2009	June 30, 2009	September 30, 2009	December 31, 2009
Year ended December 31, 2009:				
Oil and natural gas sales	$146,175	$214,303	$256,074	$300,989
Operating profit (loss) (1)	(24,332)	41,492	77,202	126,445
Net income (loss)	(43,759)	(93,163)	30,944	(11,206)
Basic earnings (loss) per share(2)	(0.46)	(0.92)	0.30	(0.12)
Diluted earnings (loss) per share(2)	(0.46)	(0.92)	0.29	(0.12)

(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 all periods presented to reflect the Company's two-for-one stock split described in Notes 8 and 13 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, 2010. 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, 2010 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, 2010 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

On February 17, 2011, our Board of Directors adopted Amended and Restated By-laws of Whiting Petroleum Corporation (the "By-laws"). The By-laws include amendments to Article III, Section 6, which relates to the term, resignation and removal of directors, to provide that D. Sherwin Artus and Allan R. Larson, both current directors, will be eligible to serve on our Board of Directors until the Annual Meeting after they have attained 77 years of age. The foregoing description is not complete and qualified in its entirety by reference to a copy of the By-laws which are filed as Exhibit 3.2 to this Annual Report on Form 10-K and incorporated by reference herein.

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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 2011 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, 2010.

Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in

			the first column)	
Equity compensation plans approved by security holders(1)	296,516	$ 16.78	1,789,693	(2)
Equity compensation plans not approved by security holders	-	N/A	-	
Total	296,516	$ 16.78	1,789,693	(2)

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

(2) Excludes 869,370 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, 2010 and 2009

c. Consolidated Statements of Income for the Years ended December 31, 2010, 2009 and 2008

d. Consolidated Statements of Cash Flows for the Years ended December 31, 2010, 2009 and 2008

e. Consolidated Statements of Stockholders’ Equity and Comprehensive Income for the Years ended December 31, 2010, 2009 and 2008

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, 2010	December 31, 2009
ASSETS		
Current assets	$1,838	$1,216
Investment in subsidiaries	1,416,880	1,080,146
Intercompany receivable	1,732,681	1,814,787
Total assets	$3,151,399	$2,896,149
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities	$4,847	$6,849
Long-term debt	600,000	618,585
Other long-term liabilities	21,006	21,043
Stockholders' equity	2,525,546	2,249,672
Total liabilities and stockholders' equity	$3,151,399	$2,896,149

CONDENSED STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31, 2010	2009	2008
Operating expenses:			
General and administrative	$(7,835)	$(6,659)	$(3,619)
Interest expense	(1,844)	(2,139)	(1,830)
Equity in earnings (losses) of subsidiaries	342,671	(101,107)	255,504
Income (loss) before income taxes	332,992	(109,905)	250,055
Income tax benefit	3,661	3,023	2,088
Net income (loss)	$336,653	$(106,882)	$252,143

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,		
	2010	2009	2008
Cash flows provided by operating activities	$1,108	$2,961	$8,883
Cash flows from investing activities:			
Investment in subsidiaries	-	-	-
Cash flows from financing activities:			
Intercompany receivable	507	(260)	(5,647)
Other financing activities	(1,615)	(2,701)	(3,236)
Net cash used in financing activities	(1,108)	(2,961)	(8,883)
Net change in cash and cash equivalents	-	-	-
Cash and cash equivalents:			
Beginning of period	-	-	-
End of period	$-	$-	$-
NONCASH INVESTING ACTIVITIES:			
Conveyance to Whiting USA Trust I increasing investment in subsidiaries	$-	$-	$111,223
Sale of Whiting USA Trust I units decreasing investment in subsidiaries	$-	$-	$(93,683)
Distributions from Whiting USA Trust I decreasing investment in subsidiaries	$(5,937)	$(5,766)	$(5,212)

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, 2010	2009	2008
NONCASH FINANCING ACTIVITIES:			
Issuance of preferred stock increasing stockholders' equity	$-	$334,112	$-
Issuance of preferred stock increasing intercompany receivable	$-	$(334,112)	$-
Issuance of common stock increasing stockholders' 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 stockholders' 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 stockholders' equity	$(317,406)	$-	$-
Preferred stock cancelled in connection with its induced conversion decreasing intercompany receivable	$317,406	$-	$-
Preferred stock dividends paid decreasing stockholders' equity	$(16,441)	$(10,302)	$-
Preferred stock dividends paid decreasing intercompany receivable	$16,441	$10,302	$-
Premium on induced conversion of 6.25% convertible perpetual preferred stock decreasing stockholders' 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	$5,937	$5,766	$5,212
	$-	$-	$(111,223)

Conveyance to Whiting USA Trust I decreasing intercompany receivable			
Sale of Whiting USA Trust I units increasing intercompany receivable	$-	$-	$93,683

See notes to condensed financial statements. (Concluded)

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 the subsidiaries to make any dividend payments, distributions or other payments to the Parent Company. The restrictions apply to all of the net assets of the subsidiaries. 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, 2010 and 2009 (in thousands):

	December 31,	
	2010	2009
Long-term debt:		
6.5% Senior Subordinated Notes due 2018	$ 350,000	$ -
7% Senior Subordinated Notes due 2014	250,000	250,000
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,147	-	218,853
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $268	-	149,732
Other long-term liabilities:		
Tax sharing liability	20,707	20,744
Other	299	299
Total long-term debt and other long-term liabilities	$ 621,006	$ 639,628

Scheduled maturities of the Parent Company's long-term debt and other long-term liabilities (including the current portions thereof) as of December 31, 2010 were as follows (in thousands):

	2011	2012	2013	2014	2015	Thereafter	Total
Amounts Due	$ 1,786	$ 1,647	$ 1,540	$ 267,520	$ -	$ 350,000	$ 622,493

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

3. STOCKHOLDERS' EQUITY

6.25% Convertible Perpetual Preferred Stock Offering—In June 2009, the Parent Company completed a public offering of 6.25% convertible perpetual preferred stock, selling 3,450,000 shares at a price of $100.00 per share and providing net proceeds of $334.1 million after underwriters' fees and offering expenses. The net proceeds were used to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement.

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Induced Conversion of 6.25% Convertible Perpetual Preferred Stock. In August 2010, the Registrant 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 Parent 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.

Common Stock Offering—In February 2009, the Parent 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 net proceeds were used to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement.

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

4. WHITING USA TRUST I

On April 30, 2008, the Parent Company completed an initial public offering of units of beneficial interest in Whiting USA Trust I (the "Trust"), selling 11,677,500 Trust units at $20.00 per Trust unit, and providing net proceeds of $193.7 million after underwriters' fees, offering expenses and post-close adjustments. The Parent Company used the offering net proceeds to repay a portion of the debt outstanding under Whiting Oil and Gas' credit agreement. Immediately prior to the closing of the offering, Whiting Oil and Gas conveyed a term net profits interest in certain of its oil and natural gas properties to the Trust in exchange for 13,863,889 Trust units, which Trust units were in turn transferred from Whiting Oil and Gas to the Parent Company. The Parent Company retained 15.8%, or 2,186,389 Trust units, of the total Trust units issued and outstanding.

The net profits interest entitles the Trust to receive 90% of the net proceeds from the sale of oil and natural gas production from the underlying properties. The net profits interest will terminate at the time when 9.11 MMBOE have been produced and sold from the underlying properties. This is the equivalent of 8.20 MMBOE in respect of the Trust's right to receive 90% of the net proceeds from such production pursuant to the net profits interest.

5. SUBSEQUENT EVENTS

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

Stock split. On January 26, 2011, the Board of Directors approved a two-for-one split of the Registrant's shares of common stock to be effected in the form of a stock dividend. As a result of the stock split, stockholders of record on February 7, 2011 received one additional share of common stock for each share of common stock held. The additional shares of common stock were distributed on February 22, 2011. All common share and per share amounts in these notes to the condensed financial statements have been retroactively adjusted to reflect the stock split for all periods presented. The common stock dividend will result in the conversion price for Parent Company's 6.25% Convertible Perpetual Preferred Stock being adjusted from $43.4163 to $21.70815.

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Preferred stock dividend. On February 15, 2011, the Parent 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, 2011 to holders of record on March 1, 2011.

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SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized, on this 24th day of February, 2011.

WHITING PETROLEUM CORPORATION

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

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

Signature	Title	Date
/s/ James J. Volker James J. Volker	Chairman and Chief Executive Officer and Director (Principal Executive Officer)	February 24, 2011
/s/ Michael J. Stevens Michael J. Stevens	Vice President and Chief Financial Officer (Principal Financial Officer)	February 24, 2011
/s/ Brent P. Jensen Brent P. Jensen	Controller and Treasurer (Principal Accounting Officer)	February 24, 2011
/s/ Thomas L. Aller Thomas L. Aller	Director	February 24, 2011
/s/ D. Sherwin Artus D. Sherwin Artus	Director	February 24, 2011
/s/ Thomas P. Briggs Thomas P. Briggs	Director	February 24, 2011
/s/ Philip E. Doty Philip E. Doty	Director	February 24, 2011
	Director	February 24, 2011

/s/ William N. Hahne William N. Hahne		
/s/ Allan R. Larson Allan R. Larson	Director	February 24, 2011

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(3.1)	Restated Certificate of Incorporation of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.2 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2010 (File No. 001-31899)].
(3.2)	Amended and Restated By-laws of Whiting Petroleum Corporation, effective February 17, 2011.
(4.1)	Fifth Amended and Restated Credit Agreement, dated as of October 15, 2010, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, the lenders party thereto, JPMorgan Chase Bank, N.A., as Administrative Agent, and the various other agents party thereto [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 15, 2010 (File No. 001-31899)].
(4.2)	Subordinated Indenture, dated as of April 19, 2005, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting Programs, Inc., Equity Oil Company and The Bank of New York Trust Company, N.A., as successor trustee [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 21, 2010 (File No. 001-31899)].
(4.3)	Second Supplemental Indenture, dated September 24, 2010, among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation and The Bank of New York Mellon Trust Company, N.A., as Trustee, creating the 6.5% Senior Subordinated Notes due 2018 [Incorporated by reference to Exhibit 4.2 to Whiting Petroleum Corporation's Current Report on Form 8-K dated September 21, 2010 (File No. 001-31899)].
(4.4)	Indenture, dated October 4, 2005, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and The Bank of New York Trust Company, N.A., as successor trustee [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 4, 2005 (File No. 001-31899)].
(4.5)	Rights Agreement, dated as of February 23, 2006, between Whiting Petroleum Corporation and Computershare Trust Company, Inc. [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated February 23, 2006 (File No. 001-31899)].
(10.1)*	Whiting Petroleum Corporation 2003 Equity Incentive Plan, as amended through October 23, 2007 [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 23, 2007 (File No. 001-31899)].
(10.2)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for time-based vesting awards prior to October 23, 2007 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2004 (File No. 001-31899)].
(10.3)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for performance vesting awards prior to October 23, 2007 [Incorporated by reference to Exhibit 10.1 to Whiting

	Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2007 (File No. 001-31899)].
(10.4)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for performance vesting awards on and after October 23, 2007 and prior to February 23, 2008 [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 23, 2007 (File No. 001-31899)].

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Exhibit Number	Exhibit Description
(10.5)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for time-based vesting awards on and after October 23, 2007 [Incorporated by reference to Exhibit 10.4 to Whiting Petroleum Corporation's Current Report on Form 8-K dated October 23, 2007 (File No. 001-31899)].
(10.6)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan for performance vesting awards on and after February 23, 2008 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended March 31, 2008 (File No. 001-31899)].
(10.7)*	Whiting Petroleum Corporation Production Participation Plan, as amended and restated February 4, 2008 [Incorporated by reference to Exhibit 10.6 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 001-31899)].
(10.8)	Tax Separation and Indemnification Agreement between Alliant Energy Corporation, Whiting Petroleum Corporation and Whiting Oil and Gas Corporation [Incorporated by reference to Exhibit 10.3 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].
(10.9)*	Summary of Non-Employee Director Compensation for Whiting Petroleum Corporation.
(10.10)*	Production Participation Plan Credit Service Agreement, dated February 23, 2007, between Whiting Petroleum Corporation and James J. Volker [Incorporated by reference to Exhibit 10.7 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2006 (File No. 001-31899)].
(10.11)*	Amended and Restated Production Participation Plan Supplemental Payment Agreement, dated January 14, 2008, between Whiting Petroleum Corporation and J. Douglas Lang [Incorporated by reference to Exhibit 10.6 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2007 (File No. 001-31899)].
(10.12)*	Form of Indemnification Agreement for directors and executive officers of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 10.10 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2008 (File No. 001-31899)].
(10.13)*	Form of Executive Excise Tax Gross-Up Agreement for executive officers of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated January 13, 2009 (File No. 001-31899)].
(10.14)*	Form of Stock Option Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan [Incorporated by reference to Exhibit 10.14 to Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2008 (File No. 001-31899)].
(21)	Subsidiaries of Whiting Petroleum Corporation.
(23.1)	Consent of Deloitte & Touche LLP.
(23.2)	Consent of Cawley, Gillespie & Associates, Inc., Independent Petroleum Engineers.

(31.1)	Certification by the Chairman and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President and Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(32.1)	Certification of the Chairman and Chief Executive Officer pursuant to 18 U.S.C. Section 1350.
(32.2)	Certification of the Vice President and Chief Financial Officer pursuant to 18 U.S.C. Section 1350.

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Exhibit Number	Exhibit Description
(99.1)	Proxy Statement for the 2011 Annual Meeting of Stockholders, to be filed within 120 days of December 31, 2010 [To be filed with the Securities and Exchange Commission under Regulation 14A within 120 days after December 31, 2010; except to the extent specifically incorporated by reference, the Proxy Statement for the 2011 Annual Meeting of Stockholders shall not be deemed to be filed with the Securities and Exchange Commission as part of this Annual Report on Form 10-K].
(99.2)	Report of Cawley, Gillespie & Associates, Inc., Independent Petroleum Engineers.
(101)	The following materials from Whiting Petroleum Corporation's Annual Report on Form 10-K for the year ended December 31, 2010 are furnished herewith, formatted in XBRL (Extensible Business Reporting Language): (i) the Consolidated Balance Sheets as of December 31, 2010 and 2009, (ii) the Consolidated Statements of Income for the Years Ended December 31, 2010, 2009 and 2008, (iii) the Consolidated Statements of Cash Flow for the Years Ended December 31, 2010, 2009 and 2008, (iv) the Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Years Ended December 31, 2010, 2009 and 2008 and (v) Notes to Consolidated Financial Statements.

* A management contract or compensatory plan or arrangement.