WHITING PETROLEUM CORP
Form 10-K
March 01, 2010

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, 2009

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)

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

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	New York Stock Exchange

Purchase Rights (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. YesT No£

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes £ No £

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

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

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

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

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2009: $1,794,225,805.

Number of shares of the registrant's common stock outstanding at February 15, 2010: 50,843,843 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2010 Annual Meeting of Stockholders are incorporated by reference into Part III.

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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.

“flush production” The high rate of flow from a well during initial production immediately after it is brought on-line.

“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.

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"MMBOE" One million BOE.

"MMBtu" One million British Thermal Units.

"MMcf" One million cubic feet of natural gas.

"MMcf/d" One MMcf per day.

"MMcfe" One million cubic feet of natural gas equivalent.

"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.

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

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

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PART I

Item 1. Business

Overview

We are an independent oil and gas company engaged in acquisition, development, exploitation, production and exploration activities primarily in the 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, 2009, our estimated proved reserves totaled 275.0 MMBOE, representing a 15% increase in our proved reserves since December 31, 2008. Our 2009 average daily production was 55.5 MBOE/d and implies an average reserve life of approximately 13.6 years.

The following table summarizes our estimated proved reserves by core area, the corresponding pre-tax PV10% value and our standardized measure of discounted future net cash flows as of December 31, 2009, and our December 2009 average daily production:

	Proved Reserves(1)					
Core Area	Oil(2) (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil(2)	Pre-Tax PV10% Value(3) (In millions)	December 2009 Average Daily Production (MBOE/d)
Permian Basin	112.3	66.2	123.3	91 %	$ 901.3	11.7
Rocky Mountains	70.2	159.4	96.8	73 %	1,266.3	30.3
Mid-Continent	36.6	15.2	39.1	94 %	581.3	9.3
Gulf Coast	2.3	36.6	8.4	27 %	69.6	3.0
Michigan	2.4	30.0	7.4	32 %	57.2	2.3
Total	223.8	307.4	275.0	81 %	$ 2,875.7	56.6
Discounted Future Income Taxes	-	-	-	-	(532.2)	-
Standardized Measure of Discounted Future Net Cash Flows	-	-	-	-	$ 2,343.5	-

(1) Oil and gas reserve quantities and related discounted future net cash flows have been derived from oil and gas prices calculated using an average of the first-day-of-the month price for each month within the most recent 12 months, 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 2009, we incurred $577.9 million in acquisition, development and exploration activities, including $479.8 million for the drilling of 145 gross (56.2 net) wells. Of these new wells, 51.1 (net) resulted in productive completions and 5.1 (net) were unsuccessful, yielding a 91% success rate. Our current 2010 capital budget for exploration and development expenditures is $830.0 million, which we expect to fund with net cash provided by our operating activities. Our 2010 capital budget of $830.0 million represents a substantial increase from the $479.8 million incurred on exploration and development expenditures during 2009. This increased capital budget is in response to the higher oil and natural gas prices experienced during the second half of 2009 and continuing into the first part of 2010.

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.

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 additional royalty and overriding interests acquisition 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. 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.

We completed the second additional royalty and overriding interests acquisition 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.

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. We funded these acquisitions primarily with net cash provided by our operating activities.

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.

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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. We used these proceeds to repay a portion of the debt outstanding under our credit agreement.

2008 Acquisitions. In May 2008, we 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 acquisition price of $365.0 million. After allocating $79.5 million of the purchase price to unproved properties, the resulting acquisition cost is $2.48 per Mcfe. Of the estimated 115.2 Bcfe of proved reserves acquired as of the January 1, 2008 acquisition effective date, 98% are natural gas and 22% are proved developed producing. The average daily net production from the properties was 17.8 MMcfe/d as of the acquisition effective date. We funded the acquisition with borrowings under our credit agreement.

2008 Divestitures. 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, providing net proceeds of $193.8 million after underwriters’ fees, offering expenses and post-close adjustments. We used the net offering proceeds to repay a portion of the debt outstanding under our credit agreement. The net proceeds from the sale of Trust 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 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, and these reserve quantities are projected to be produced by August 31, 2018, based on the reserve report for the underlying properties as of December 31, 2009. 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%, or 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%, or 3.1 MBOE/d, of our March 2008 average daily net production.

Business Strategy

Our goal is to generate meaningful growth in our net asset value per share for 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 Piceance Basin projects has become one of our central objectives. We have assembled approximately 118,000 gross (69,600 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, 2010, we have participated in the drilling of 123 successful wells (88 operated) in our Sanish field acreage that had a combined net production rate of 12.6 MBOE/d during December 2009.

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As of December 31, 2009, we have assembled 213,500 gross (127,800 net) acres in the Lewis & Clark Prospect in Golden Valley and Billings Counties, North Dakota. Subsequent to year-end we assembled additional acreage, primarily in Stark County, North Dakota, which brings our total acreage position in the Lewis & Clark area to 320,000 gross (202,400 net) acres. Through the end of 2009 we have drilled three horizontal wells into the Three Forks reservoir at Lewis & Clark and are very encouraged with the results. We intend to further delineate this area with additional drilling in 2010.

With the acquisition of Equity Oil Company in 2004, we acquired mineral interests and federal oil and gas leases in the Piceance Basin of Colorado, where we have found the Iles and Williams Fork reservoirs (Mesaverde formation) to be gas productive at our Sulphur Creek field area and the Mesaverde formation to be gas productive at our Jimmy Gulch prospect area.

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 our Piceance projects and at the Flat Rock Gas field we have entered into 5-year fixed-price gas contracts at over $5.00 per Mcf to enhance the economics of further drilling and development in this area and thereby maintain the economic viability of this production.

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, 2009, we have identified a drilling inventory of over 1,400 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 and anticipate further significant production increases in these fields over the next four to seven years through the use of secondary and tertiary recovery techniques. 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 2009, we completed 15 separate acquisitions of producing properties for estimated proved reserves of 230.7 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.

Balanced, Long-Lived Asset Base. As of December 31, 2009, we had interests in 9,616 gross (3,719 net) productive wells across approximately 1,059,500 gross (545,300 net) developed acres in our five core geographical areas. We believe this geographic mix of properties and organic drilling opportunities, combined with our continuing business strategy of acquiring and exploiting properties in these areas, presents us with multiple opportunities in executing our strategy because we are not dependent on any particular producing regions or geological formations. Our proved reserve life is approximately 13.6 years based on year-end 2009 proved reserves and 2009 production.

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Experienced Management Team. Our management team averages 26 years of experience in the oil and gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, each of our acquisition professionals has at least 29 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

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 6,370 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 14 professionals averaging over 21 years of expertise managing CO2 floods. This provides us with the ability to pursue other CO2 flood targets and employ this technology to add reserves to our portfolio. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

In June 2009, we implemented a “Drill Well on Paper” (“DWOP”) process on our drilling program in the Sanish field in North Dakota. This process involves everyone who partakes in the drilling of a well and analyzes what synergies exist to reduce the cost to drill a well. The first step in the process is to determine the time required to drill a well assuming everything went right (drill the well on paper). The next steps are how to apply this to drill the perfect well in the field. Prior to starting the project the number of days from well spud to total depth averaged 38 days. As of the end of February 2010, we have reduced drilling time by 11 days to an average of 27 days, resulting in meaningful cost reductions. We will expand this program to all of our Sanish field rigs in 2010.

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Proved, Probable and Possible Reserves

Our estimated proved, probable and possible reserves as of December 31, 2009 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	Future Capital Expenditures (In millions)
PDP	36.3	24.8	40.4	33 %	
PDNP	25.4	11.9	27.4	22 %	
PUD	50.6	29.5	55.5	45 %	
Total Proved	112.3	66.2	123.3	100 %	$ 921.6
Total Probable	41.4	50.2	49.7		$ 338.0
Total Possible	89.8	13.5	92.1		$ 433.0
Rocky Mountains:					
PDP	48.4	74.8	60.9	63 %	
PDNP	0.5	1.9	0.8	1 %	
PUD	21.3	82.7	35.1	36 %	
Total Proved	70.2	159.4	96.8	100 %	$ 333.1
Total Probable	12.0	107.1	29.9		$ 357.5
Total Possible	69.9	130.7	91.7		$ 828.8
Mid-Continent:					
PDP	28.6	13.1	30.8	79 %	
PDNP	1.5	0.5	1.6	4 %	
PUD	6.5	1.6	6.7	17 %	
Total Proved	36.6	15.2	39.1	100 %	$ 107.7
Total Probable	2.3	0.0	2.3		$ 40.3
Total Possible	2.7	0.8	2.8		$ 33.6
Gulf Coast:					
PDP	1.7	18.7	4.8	57 %	
PDNP	0.3	3.8	0.9	11 %	
PUD	0.3	14.1	2.7	32 %	
Total Proved	2.3	36.6	8.4	100 %	$ 37.0
Total Probable	1.6	22.4	5.3		$ 56.5
Total Possible	3.5	30.4	8.6		$ 116.5
Michigan:					
PDP	1.1	25.5	5.4	73 %	
PDNP	1.0	3.8	1.6	22 %	
PUD	0.3	0.7	0.4	5 %	
Total Proved	2.4	30.0	7.4	100 %	$ 6.3
Total Probable	1.5	2.2	1.9		$ 13.4
Total Possible	0.7	9.5	2.3		$ 27.0

Total Company:						
PDP	116.1	156.9	142.3	52	%	
PDNP	28.7	21.9	32.3	12	%	
PUD	79.0	128.6	100.4	36	%	
Total Proved	223.8	307.4	275.0	100	%	$ 1,405.7
Total Probable	58.8	181.9	89.1			$ 805.7
Total Possible	166.6	184.9	197.5			$ 1,438.9

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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 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. During 2007, sales to Valero Energy Corporation and Plains Marketing LP accounted for 14% and 13%, respectively, of our total oil and natural gas sales.

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 (“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 nonprice controls affecting wellhead sales of natural gas, effective January 1, 1993. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business.

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

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

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

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. After a final rule was implemented by the U.S. Department of Transportation on March 15, 2006 that defines and puts new safety requirements on gas gathering pipelines, we have screened our gas gathering lines and are implementing programs to comply with applicable requirements of this section.

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 (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.