WHITING PETROLEUM CORP
Form 10-K
February 28, 2008

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, 2007

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:

Common Stock, $0.001 par value	New York Stock Exchange New York Stock Exchange

Preferred Share 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.YesTNo£

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£NoT

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.YesTNo£

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£NoT

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2007: $1,494,294,777.

Number of shares of the registrant's common stock outstanding at February 15, 2008: 42,241,356 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2008 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 operating subsidiaries. When the context requires, we refer to these entities separately.

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

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

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

"Bcf" One billion cubic feet of natural gas.

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

"BOE/d" One BOE per day.

"Bopd" Barrels of oil or other liquid hydrocarbons per day.

"CO2 flood" A tertiary recovery method in which CO2 is injected into a reservoir to enhance oil 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.

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

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

"MBOE" One thousand BOE.

"MBOE/d" One thousand BOE per day.

"Mcf" One thousand cubic feet of natural gas.

"Mcf/d" One Mcf per day.

"MMbbl" One million barrels of oil or other liquid hydrocarbons.

"MMBOE" One million BOE.

"MMbtu" One million British Thermal Units.

"MMcf" One million cubic feet of natural gas.

"MMcf/d" One MMcf per day.

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“NGLs” Natural gas liquids.

“PDNP” Proved developed nonproducing.

“PDP” Proved developed producing.

“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.

“PUD” Proved undeveloped.

“pre-tax PV10%” The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with Securities and Exchange Commission (“SEC”) guidelines, 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, 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” for more information.

“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.

“working interest” The interest in an 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 to share in production, subject to all royalties, overriding royalties and other burdens and to share in all costs of exploration, development, 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, 2007, our estimated proved reserves totaled 250.8 MMBOE, representing a 1% increase in our proved reserves since December 31, 2006. Our estimated December 2007 average daily production was 40.3 MBOE/d and implies an average reserve life of approximately 17.1 years.

The following table summarizes our estimated proved reserves by core area, the corresponding pre-tax PV10% value, our standardized measure of discounted future net cash flows as of December 31, 2007, and our December 2007 average daily production:

Core Area	Proved Reserves: Oil (MMbbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value(1) (In millions)	December 2007 Average Daily Production (MBOE/d)
Permian Basin	100.7	76.0	113.4	89%	$ 2,483.0	10.7
Rocky Mountains	42.2	116.9	61.7	68%	1,418.0	14.8
Mid-Continent	46.0	30.6	51.1	90%	1,418.0	7.2
Gulf Coast	3.5	52.5	12.3	29%	284.7	4.1
Michigan	3.9	50.7	12.3	32%	254.6	3.5
Total	196.3	326.7	250.8	78%	$ 5,858.3	40.3
Discounted Future Income Taxes	-	-	-	-	(1,846.6)	-
Standardized Measure of Discounted Future Net Cash Flows	-	-	-	-	$ 4,011.7	-

(1) 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 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 oil and natural gas reserves.

While historically we have grown through acquisitions, 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.

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Our growth plan is centered on the following activities:

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

During 2007, we incurred $578.2 million in acquisition, development and exploration activities, including $529.3 million for the drilling of 277 gross (138.6 net) wells. Of these new wells, 271 resulted in productive completions and 6 were unsuccessful, yielding a 98% success rate. We have budgeted $640.0 million for exploration and development drilling expenditures in 2008.

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.

2007 Acquisitions. There were no significant acquisitions during the year ended December 31, 2007.

2007 Divestitures. On July 17, 2007, we sold our approximate 50% non-operated working interest in several gas fields located in the LaSalle and Webb Counties of Texas for total cash proceeds of $40.1 million, resulting in a pre-tax gain on sale of $29.7 million. The divested properties had estimated proved reserves of 2.3 MMBOE as of December 31, 2006, adjusted to the July 1, 2007 divestiture effective date, thereby yielding a sale price of $17.77 per BOE. The June 2007 average daily net production from these fields was 0.8 MBOE/d.

During 2007, we sold our interests in several additional non-core properties for an aggregate amount of $12.5 million in cash for total estimated proved reserves of 0.6 MMBOE as of the divestitures' effective dates. The divested properties are located in Colorado, Louisiana, Michigan, Montana, New Mexico, North Dakota, Oklahoma, Texas and Wyoming. The average daily net production from the divested property interests was 0.3 MBOE/d as of the dates of disposition.

2006 Acquisitions. On August 29, 2006, we acquired a 15% working interest in approximately 170,000 acres of unproved properties in the central Utah Hingeline play for $25.0 million. No producing properties or proved reserves were associated with this acquisition. As part of this transaction, the operator agreed to pay 100% of our drilling and completion costs for the first three wells in the project.

On August 15, 2006, we acquired 65 producing properties, a gathering line, gas processing plant and 30,437 net acres of leasehold held by production in Michigan. The purchase price was $26.0 million for estimated proved reserves of 1.4 MMBOE as of the acquisition effective date of May 1, 2006, resulting in a cost of $18.55 per BOE of estimated proved reserves. Proved developed reserve quantities represented 99% of the total proved reserves acquired. The average net production from the properties was 0.6 MBOE/d as of the acquisition effective date. We operate 85% of the acquired properties.

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We funded our 2006 acquisitions with cash on hand and borrowings under our credit agreement.

2006 Divestitures. During 2006, we sold our interests in several non-core properties for an aggregate amount of $24.4 million in cash for total estimated proved reserves of 1.4 MMBOE as of the effective dates of the divestitures. The divested properties included interests in the Cessford field in Alberta, Canada; Permian Basin of West Texas and New Mexico; and the Ashley Valley field in Uintah County, Utah. The average net production from the divested property interests was 0.4 MBOE/d as of the effective dates of disposition, and we recognized a pre-tax gain on sale of $12.1 million related to these property sales.

Business Strategy

Our goal is to generate meaningful growth in both production and free cash flow by investing in oil and gas projects with attractive rates of return on capital employed. To date, we have achieved this goal largely through the acquisition of additional reserves as well as continued field development in our core areas. Based on the extensive property base we have built, we now have several economically attractive opportunities to exploit and develop within our oil and gas properties and several opportunities to explore our acreage positions for production growth and additional 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 118,348 gross (83,033 net) acres on the eastern side of the Williston Basin in North Dakota in an active oil exploration play at our Robinson Lake prospect area, where the Middle Bakken reservoir is oil productive. 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 to be gas productive at our Boies Ranch prospect area and the Williams Fork reservoir to be gas productive at our Jimmy Gulch prospect area. Our initial drilling results in both projects have been encouraging. We have drilled five wells in our Robinson Lake acreage, which could support up to 90 locations on 1,280-acre spacing. In the Piceance acreage, we have completed three wells and have identified 110 drilling locations based on 20-acre spacing.

Developing and Exploiting Existing Properties. Our existing property base and our acquisitions over the past three years have provided us with numerous low-risk opportunities for exploitation and development drilling. As of December 31, 2007, we have identified a drilling inventory of over 1,900 gross wells that we believe will add substantial production over the next five years. Our drilling inventory consists largely of the development of our 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 anticipate significant production increases in these fields over the next five 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 2007, we completed 13 acquisitions of producing properties totaling 208.4 MMBOE of estimated total proved reserves, as of the respective acquisition effective dates. Our experienced team of management, 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 acquire properties complementary to our core operating areas.

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Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity price volatility. We have historically funded our acquisitions and growth activity through a combination of equity and debt issuances, bank borrowings and internally generated cash flow, as appropriate, to maintain our strong financial position. We are also evaluating the sale of non-core properties. We expect to use the net proceeds from the 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 to provide an attractive base commodity price level, while maintaining the ability to benefit from improvements in commodity prices.

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, 2007, we had interests in 8,458 gross (3,565 net) productive wells across 934,723 gross (481,647 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. As a result of our acquisitions of the Postle and North Ward Estes properties in 2005, we have enhanced the production stability and reserve life of our developed reserves. Additionally, these properties contain identified growth opportunities that we expect will significantly increase production.

Experienced Management Team. Our management team averages 25 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 26 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 5,694 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 26 years of expertise in 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.

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Proved Reserves

Our estimated proved reserves as of December 31, 2007 are summarized in the table below.

	Oil (MMbbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Future Capital Expenditures (In millions)
Permian Basin:					
PDP	30.7	41.7	37.6	33%	
PDNP	21.2	8.5	22.6	20%	
PUD	48.8	25.8	53.2	47%	
Total Proved	100.7	76.0	113.4	100%	$ 704.0
Rocky Mountains:					
PDP	34.9	68.6	46.4	75%	
PDNP	1.3	15.5	3.9	6%	
PUD	6.0	32.8	11.4	19%	
Total Proved	42.2	116.9	61.7	100%	$ 160.6
Mid-Continent:					
PDP	27.4	23.9	31.4	61%	
PDNP	6.6	2.8	7.1	14%	
PUD	12.0	3.9	12.6	25%	
Total Proved	46.0	30.6	51.1	100%	$ 264.7
Gulf Coast:					
PDP	2.1	29.7	7.1	58%	
PDNP	0.3	5.0	1.1	9%	
PUD	1.1	17.8	4.1	33%	
Total Proved	3.5	52.5	12.3	100%	$ 41.1
Michigan:					
PDP	1.7	37.5	7.9	64%	
PDNP	1.1	3.8	1.7	14%	
PUD	1.1	9.4	2.7	22%	
Total Proved	3.9	50.7	12.3	100%	$ 16.4
Total Company:					
PDP	96.8	201.4	130.4	52%	
PDNP	30.5	35.6	36.4	15%	
PUD	69.0	89.7	84.0	33%	
Total Proved	196.3	326.7	250.8	100%	$ 1,186.8

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. Our marketing of oil and gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. During 2007, sales to Plains Marketing LP and Valero Energy Corporation accounted for 13% and 14%, respectively, of our total oil and natural gas sales. During 2006, sales to Plains Marketing LP and Valero Energy Corporation accounted for 16% and 12%, respectively, of our total oil and natural gas sales. During 2005, sales to Teppco Crude Oil LLC accounted for 10% of our total oil and natural gas sales.

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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 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 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 sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms of access to pipeline transportation 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. 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.

FERC implements The Outer Continental Shelf Lands Act as to transportation and pipeline issues, which requires that all pipelines operating on or across the outer continental shelf provide open access, 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.

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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 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.

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 are screening all of our pipeline systems to determine if the new rules apply. In addition, many state agencies have adopted these new federal regulations. As the agencies continue to work on interpreting the definitions in the rule, we continue to evaluate which pipelines may be subject to the new regulations. These new regulations may put some of our gas gathering lines under the same level of scrutiny that transmission lines have seen in the past. The new regulations impose additional costly regulatory requirements on previously unregulated pipelines.

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 sales of crude oil 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. A review of these regulations by the FERC in 2000 was successfully challenged on appeal by an association of oil pipelines. As a result, the FERC in February 2003 increased the index slightly, effective July 2001. Intrastate oil pipeline transportation rates are subject to regulation by state regulatory commissions. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis. Under this open access standard, common carriers must offer service to all shippers requesting service on the same terms and under the same rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines' published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

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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 reports concerning 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 and 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, or MMS, and are 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 our development and production plans for these leases. 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 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 laying 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 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, also known as "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, if the problem itself is not discovered until years later. Our properties, adjacent affected properties, the disposal sites, 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, also known as "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, also known as "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 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" and thus we are not required to comply with a substantial portion of RCRA's requirements because our operations generate minimal quantities of hazardous wastes. However, these wastes may be regulated by EPA or 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.

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Historically, 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 permitting of oil and gas construction projects. There are still some States that regulate the discharge of storm water from 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 Clean Water Act 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, or 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 will require the amendment of SPCC plans and the modification of spill control devices at many facilities. The due date for having plans completed and control devices in place was extended on December 12, 2005 with the new compliance date being October 31, 2007. On May 16, 2007 the EPA extended the compliance dates until July 1, 2009 for both completion and implementation of the plan. The extension will allow time for the EPA to complete additional rule amendments and guidance documents. On October 15, 2007 the EPA proposed amendments to the 2002 SPCC rule to provide increased clarity, to tailor requirements to particular industry sectors, and to streamline certain requirements for a facility owner or operator subject to the rule. The EPA expects to finalize this proposed rule by the summer of 2008. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution and that any amendment and subsequent implementation of our SPCC plans will be performed in a timely manner and not have a significant impact on our operations.

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 work 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 are being 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 and that we hold or have applied for all permits necessary to our operations.

Global Warming and Climate Control. Recent scientific studies have suggested that emissions of certain gases, commonly referred to as "greenhouse gases" and including carbon dioxide and methane, may be contributing to warming of the Earth's atmosphere. In response to such studies, the U.S. Congress is actively considering legislation to reduce emissions of greenhouse gases. In addition, at least 17 states have already taken legal measures to reduce emissions of greenhouse gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Also, as a result of the U.S. Supreme Court's decision on April 2, 2007 in Massachusetts, et al. v. EPA, the EPA may be required to regulate greenhouse gas emissions from mobile sources (e.g., cars and trucks) even if Congress does not adopt new legislation specifically addressing emissions of greenhouse gases. The Court's holding in Massachusetts that greenhouse gases fall under the federal Clean Air Act's definition of "air pollutant" may also result in future regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas where we operate could adversely affect demand for oil and gas products that, in turn, could have a significant impact on our operations.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operations frequently require licenses, permits and/or other governmental approvals. Several federal statutes, including the Outer Continental Shelf Lands Act, 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 these regulations.

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Employees

As of December 31, 2007, we had 412 full-time employees, including 29 senior level geoscientists and 38 petroleum engineers. Our employees are not represented by any labor unions. We consider our relations with our employees to be satisfactory, and have never experienced a work stoppage or strike.

Available Information

We maintain a website at the address www.whiting.com. We are not including the information contained on our website as part of, or incorporating it by reference into, this report. We make available free of charge (other than an investor's own Internet access charges) through our website our Annual Report on Form 10-K, quarterly reports on Form 10-Q and current reports on Form 8-K, 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.

A substantial or extended decline in oil and gas prices may adversely affect our business, financial condition, results of operations or cash flows.

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. These markets will likely continue to be volatile in the future. The prices we receive for our production and the levels of 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.

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Lower oil and gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and gas that we can produce economically. A substantial or extended decline in oil or gas prices may materially and adversely affect our future business, financial condition, 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.

Drilling for and producing oil and 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 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 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 this Item 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 equipment, including drilling rigs, CO2 and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and storms;
- reductions in oil and gas prices; and
- title problems.

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. The analogies we draw from available data from other wells, more fully explored prospects or 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.

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

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage. As of December 31, 2007, we had identified and scheduled over 1,900 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, 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 natural 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 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.

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 natural gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO2. Our CO2 contracts permit the suppliers to reduce the amount of CO2 they provide to us in certain circumstances. If this occurs, we may not have sufficient CO2 to produce oil and natural gas in the manner or to the extent that we anticipate. These contracts are also structured as “take-or-pay” arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO2 as part of our enhanced recovery techniques.

Our acquisition activities may not be successful.

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

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

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

As of December 31, 2007, undeveloped reserves comprised 56% of the North Ward Estes field's total estimated proved reserves and 27% of Postle field's estimated total proved reserves. To fully develop these reserves, we expect to incur total future development costs of $625.2 million at the North Ward Estes field and $258.7 million at the Postle field. During 2007 and 2006, the estimated future capital expenditures necessary to develop the proved reserves at the North Ward Estes field and Postle field increased substantially. The increases were due to several factors, including equipment and service cost inflation, higher CO_2 unit costs and volumes, higher costs associated with the expanded scope of previously identified projects, as well as new projects identified during 2006. Together, these fields encompass 75% of our estimated total future development costs related to proved 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. Therefore, ultimate recoveries from these fields may not match current expectations.

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 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.

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 to 2007, we completed 13 separate acquisitions of producing properties with a combined purchase price of $1,474.8 million for estimated proved reserves as of the effective dates of the acquisitions of 208.4 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 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.

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Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform 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.

If oil and 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 review periodically the carrying value of our oil and gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, 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. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

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, 2007, we had $250.0 million in outstanding indebtedness under Whiting Oil and Gas Corporation's ("Whiting Oil and Gas") credit agreement with $650.0 million of available borrowing capacity, as well as $620.0 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' credit agreement.

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

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

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. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas' credit agreement is periodically redetermined based on an evaluation of our 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.

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

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

The indentures governing our senior subordinated notes and Whiting Oil and Gas' credit agreement contain various restrictive covenants that may potentially 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' credit agreement also requires us to maintain a certain working capital ratio and a certain debt to EBITDAX (as defined in the credit agreement) ratio.

If we fail to comply with the restrictions in the indentures governing our senior subordinated notes or Whiting Oil and Gas' credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

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Our exploration and development operations require substantial capital, and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our oil and 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 gas reserves. To date, we have financed capital expenditures primarily with bank borrowings and cash generated by operations. We intend to finance our future capital expenditures with cash flow from operations and our existing financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and gas we are able to produce from existing wells;
- the prices at which oil and gas are sold; 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 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 gas reserves.

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 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 report.

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 gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and gas reserves are inherently imprecise.

Actual future production, oil and gas prices, revenues, taxes, exploration and development expenditures, operating expenses and quantities of recoverable oil and 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 report. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and gas prices and other factors, many of which are beyond our control.

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It should not be assumed 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 oil and gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value 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, 2007 would have decreased from $4,011.7 million to $4,002.2 million. If oil prices decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2007 would have decreased from $4,011.7 million to $3,959.8 million.

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

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

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 sometimes trade at a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. 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 gas exploration and production activities are subject to all of the operating risks associated with drilling for and producing oil and 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.

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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.

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 gas production depends on a number of factors, including the demand for and supply of oil and 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. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because access to natural gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

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

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

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

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

Our operations may incur substantial 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. Federal law and some state laws also 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 any changes 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. For instance, in response to studies suggesting that emissions of certain gases, commonly referred to as greenhouse gases and including carbon dioxide and methane, may be contributing to warming of the Earth’s atmosphere, the U.S. Congress is actively considering legislation, and more than a dozen states have already taken legal measures to reduce emission of these gases, primarily through the planned development of greenhouse gas emission inventories and/or regional greenhouse gas cap and trade programs. Moreover, the U.S. Supreme Court only recently held in a case, Massachusetts, et al. v. EPA , that greenhouse gases fall within the federal Clean Air Act’s definition of “air pollutant,” which could result in the regulation of greenhouse gas emissions from stationary sources under certain Clean Air Act programs. New legislation or regulatory programs that restrict emissions of greenhouse gases in areas in which we conduct business could have an adverse affect on our operations and demand for our products.

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Unless we replace our oil and 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 gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and gas reserves and production, and therefore our cash flow and income, are highly dependent on our success in efficiently developing and exploiting our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, exploit, find or acquire additional reserves to replace our current and future production.

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

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, our Chairman, President and Chief Executive Officer; James T. Brown, our Senior Vice President; Rick A. Ross, our Vice President, Operations; Peter W. Hagist, our Vice President, Permian Operations; J. Douglas Lang, our Vice President, Reservoir Engineering/Acquisitions; David M. Seery, our Vice President of Land; Michael J. Stevens, our Vice President and Chief Financial Officer; or Mark R. Williams, our Vice President, Exploration and Development, 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.

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.

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.

Our use of oil and 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 gas production to reduce our exposure to fluctuations in the price of oil and 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 December 31, 2007, we had contracts maturing in 2008 covering the sale of 330,000 barrels of oil per month. As of December 31, 2007, we had no outstanding gas hedges, and all our oil hedges expire by December 2008. See "Quantitative and Qualitative Disclosure about Market Risk" 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 gas. 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 gas. Furthermore, if we do not engage in hedging transactions, then we may be more adversely affected by declines in oil and gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

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, 2007, the Permian Basin region contributed 113.4 MMBOE (89% oil) of estimated proved reserves to our portfolio of operations, which represents 45% of our total estimated proved reserves and contributed 10.7 MBOE/d of average daily production in December 2007. Approximately 96% of the proved reserves of our Permian Basin operations are related to properties in Texas.

North Ward Estes. The North Ward Estes field includes six base leases with 100% working interest in 58,000 gross and net acres in Ward and Winkler Counties, Texas. As of December 31, 2007, there were approximately 1,024 producing wells and 349 injection wells. 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. We also have the rights to deeper horizons under 34,140 gross acres in the North Ward Estes field. The North Ward Estes properties produced at an estimated average net daily rate of 5.1 MBOE/d during the month of December 2007. In the North Ward Estes field, the estimated proved reserves as of December 31, 2007 were 18% PDP, 26% PDNP and 56% PUD.

The North Ward Estes field was initially developed in the 1930's and full scale waterflooding was initiated in 1955. A CO_2 enhanced recovery project was implemented in the core of the field in 1989, but was terminated in 1996 after a successful top lease by a third party. We reinitiated water injection in 2006 and successfully re-pressured the pilot area. We initiated CO_2 injection into the pilot area on May 22, 2007. In January 2008, we began expanding the CO_2 flood from the pilot area into additional sections in the Phase 1 area. By the end of January 2008, we were injecting CO_2 at 120 MMcf/d, above the target rate of 100 MMcf/d of CO_2. In the fourth quarter of 2006, we began construction of a gas plant to process and separate the CO_2 from the produced gas. This plant is scheduled to start processing produced gas during the second quarter of 2008.

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We also have interests in certain other fields within the Permian Basin of Texas and New Mexico, including 2,753 producing oil and gas wells.

Keystone South, Martin and Flying W Fields. We own a 100% working interest and operate these three fields located on the Western edge of the Midland Basin. Production comes from the Clearfork Formation, with additional production from the Wichita, Wolfcamp, Devonian, Silurian, McKee and Ellenburger Formations. During 2007, we drilled three wells in the Martin field. In 2008, we have three additional wells planned at Martin and a combination of seven additional new drills and recompletions planned in Keystone South and Flying W.

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, 2007, our estimated proved reserves in the Rocky Mountain region were 61.7 MMBOE (68% oil), which represented 25% of our total estimated proved reserves, and our December 2007 daily production averaged 14.8 MBOE/d. Approximately 53% and 27% of the proved reserves of our Rocky Mountain operations are related to assets in North Dakota and Wyoming, respectively.

Robinson Lake Bakken Play. The Bakken Formation is a low permeability, unconventional reservoir consisting of highly oil saturated shale, dolomite and fine grained sand. Horizontal drilling and advanced stimulation techniques have been successfully employed in the drilling of hundreds of wells in the Elm Coulee field in Montana and more recently in the North Dakota portion of the Williston Basin. In early 2005, we embarked on an aggressive leasing program and have acquired total acreage as of year-end 2007 of 118,348 gross (83,033 net) acres primarily in Mountrail County, North Dakota for the purpose of developing a Bakken resource drilling program. As of year end 2007, we had drilled five and completed four wells, and currently have four rigs actively drilling. For 2008, we are planning to expand our drilling program to as many as nine rigs. We are planning to drill 30 to 40 operated Bakken wells during 2008.

In addition to the drilling program, we have begun construction of a gas plant to process the associated gas. The first phase of this plant is scheduled to begin receiving gas in the second quarter of 2008.

In March 2007, we purchased an interest in the Parshall field, also located in Montrail County, North Dakota. As of December 31, 2007, we owned 66,957 gross (13,470 net) acres in the Parshall area of mutual interest. This field is operated by another operator and at the end of 2007, we had participated in the drilling and completion of 24 horizontal middle Bakken wells. We expect to participate in the drilling of approximately 50 to 60 additional wells in the Parshall field during 2008.

Red River Gas Drilling Program. In 2004, we began acquiring 3-D seismic data over several Red River Formation prospects in the deeper, gas bearing part of the Williston Basin for the purpose of defining structure and reservoir distribution. To date, we have acquired nine 3-D seismic surveys in Billings, McKenzie and Williams Counties totaling 236 square miles, which we have used to target 12 new wells. We are planning on drilling seven new wells in 2008.

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Billings Nose Drilling Program. We have established a high concentration of producing wells in the Billings Nose area of Billings County, North Dakota. These assets include the Big Stick Madison Unit and North Elkhorn Ranch Unit along with much of the acreage located between these two fields. We have acquired 44 square miles of 3-D seismic data in this area and have since identified multiple opportunities in a variety of reservoirs including the Red River, Duperow, Bakken and Mission Canyon Formations. Our efforts in 2007 focused on the North Elkhorn Ranch Unit in Billings County, North Dakota. Four horizontal wellbores were drilled into the Elkhorn Ranch member of the Mission Canyon.

Nisku A Drilling Program. We made a significant exploration discovery in 2004 in western Billings County, North Dakota in the Nisku A zone and drilled ten wells in 2004. Since the discovery, we have participated in eight casing exit wells and 49 grass root wells (six drilled in 2007). We are currently investigating waterflooding the reservoir. Modeling efforts are complete and we are researching methods to install the waterflood while minimizing the surface impact as much of this project is located in the Theodore Roosevelt National Grassland, administered by the U.S. Forest Service.

Green River Basin - Siberia Ridge. Siberia Ridge is within the greater Wamsutter Arch area of Sweetwater County, Wyoming and produces from a continuous-phase gas accumulation in the Cretaceous Almond Formation at 10,500 feet. In 2004, the spacing rules governing the well density in the Siberia Ridge field were adjusted to allow for up to two wells per 160 acres. This new configuration resulted in a total of 44 additional potential locations on our acreage. Because of lease stipulations on this Federal acreage, drilling operations can begin on or after August 1st and must end by February 1st of the following year. We have been able to maintain a single well drilling program by moving the rig between Anderson Canyon (described below) and Siberia Ridge.

Our development program commenced in mid-2005 and continued in 2006 with the drilling of ten new wells. During 2007, an additional four wells were drilled. Although not budgeted currently, there is potential for additional drilling later in 2008 once the lease stipulations allow drilling operations to resume.

Green River Basin - Anderson Canyon. Anderson Canyon, North Anderson Canyon, Bird Canyon, and McDonald Draw fields are all located on the LaBarge Platform in Southwest Wyoming. We drilled six wells in 2006 and an additional 21 in 2007. We made improvements in the drilling operations, reducing the drill time from 20 days in 2006 to around nine days in 2007. We are continuing to work on refining the completion operations in an attempt to optimize the resulting production and reserves.

Sulphur Creek - Boies Ranch Area, Rio Blanco County, Colorado. The Sulphur Creek Area in the North Central Piceance Basin has the potential to be a focal point of our activity through 2009. We acquired mineral interests and federal oil and gas leases in the 2004 Equity Oil Company acquisition. As of year end 2007, we owned 16,893 gross (4,072 net) acres in the Boies Ranch and Jimmy Gulch properties in Rio Blanco County, Colorado. We are currently supplementing our leasehold in the area. Drilling by third parties near our leasehold demonstrated the presence of a continuous-phase gas resource in the Williams Fork Formation with up-hole potential in the Wasatch Formation. We drilled and completed three gas producing wells early in 2007, and during the third quarter of 2007, we moved in two rigs and drilled an additional six wells that were awaiting completion operations by year end. The rigs we moved in were specifically designed to allow numerous wells to be drilled from a pad, to reduce the footprint and surface impact. Our plans for 2008 are to have a minimum of two drilling rigs running full time in the Piceance Basin and to drill 24 twenty-acre locations on the Boies Ranch and Jimmy Gulch acreage.

Utah Hingeline. We own a 15%, non-operated, working interest in approximately 170,000 acres of leasehold in the central Utah Hingeline play. This acreage covers several prospect leads which have been identified along trend with the recent Covenant field discovery in Sevier County, Utah. As part of our acquisition of this property, the operator agreed to pay 100% our drilling and completion costs for the first three wells in the project. The first two wells have been drilled on the acreage. The first well, the Joseph Prospect, was a dry hole. The second well, the Parowan Prospect, has been drilled, cased and temporarily abandoned pending resumed operations after lease stipulations allow operations to continue early in the third quarter of 2008.

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Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. As of December 31, 2007, the Mid-Continent region contributed 51.1 MMBOE (90% oil) of proved reserves to our portfolio of operations, which represented 20% of our total estimated proved reserves and contributed 7.2 MBOE/d of average daily production in December 2007. 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 six producing units and one producing lease covering a total of approximately 25,600 gross (24,223 net) acres with working interests of 94% to 100%. Four of the units are currently active CO_2 enhanced recovery projects. As of December 31, 2007, we were injecting 111 MMcf/d of CO_2 and surpassed 120 MMcf/d in January 2008. The Postle field is the largest Morrow oil field in the U.S. The Postle properties produced at an estimated average net daily rate of 5.8 MBOE/d during the month of December 2007. In the Postle field, the estimated proved reserves as of December 31, 2007 were 58% PDP, 15% PDNP and 27% PUD.

The Postle field was initially developed in the early 1960's and unitized for waterflood in 1967. Enhanced recovery projects in the three eastern units using CO_2 was initiated in 1995. During 2007, we expanded CO_2 injection into the southern part of the fourth unit, HMU. Operations are underway to expand CO_2 injection into the northern part of HMU and to optimize flood patterns in the existing CO_2 floods, with two drilling rigs and six workover rigs in the field. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells.

We are the sole owner of the Dry Trails Gas Plant located in the Postle field. This gas processing plant separates CO_2 gas from the produced wellhead mixture of hydrocarbon and CO_2 gas, so that the CO_2 gas can be re-injected into the producing formation. Construction began in mid-2006 to increase the plant capacity from its current capacity of 40.0 MMcf/d to 80.0 MMcf/d. Construction is continuing and the plant expansion will utilize a membrane technology to separate the CO_2 from the hydrocarbon gas. The expansion is scheduled to be on line during second quarter 2008.

In addition to the producing assets and processing plant, we have a 60% interest in the 120 mile TransPetco operated CO_2 transportation pipeline, thereby assuring the delivery of CO_2 to the Postle field at a fair tariff. A long-term CO_2 purchase agreement was executed in 2005 to provide the necessary CO_2 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, 2007, the Gulf Coast region contributed 12.3 MMBOE (29% oil) of proved reserves to our portfolio of operations, which represented 5% of our total estimated proved reserves and contributed 4.1 MBOE/d of average daily production in December 2007. Approximately 79% of the proved reserves of our Gulf Coast operations are related to properties in Texas.

Edwards Trend. We own 21,950 gross (21,870 net) acres in the Word North, Yoakum, Kawitt, Sweet Home, and Three Rivers fields along the Edwards Trend in Karnes, Dewitt and Lavaca Counties, Texas. Production in the Stuart City Reef Trend comes primarily from the Edwards, Wilcox, and Sligo Formations at depths between 7,000 and 16,000 feet.

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In 2007, we farmed out interests in the Edwards to two different operators. One of these operators utilized vertical wells to access the Edwards reservoir at approximately 12,000 feet. The second operator is utilizing horizontal wellbores with swell packers to provide zonal isolation along the length of the wellbore. Results from the horizontal wellbores look encouraging. The farmout agreement required the drilling of four wells in the farmout acreage and the fourth well is just being completed. Additional horizontal wells are being planned for 2008.

In 2008, we shot a 34 square mile 3-D seismic survey along the trend in our South Runge Prospect where we own 9,054 gross (7,643 net) acres, prospecting for expanded Wilcox. We believe the results of the seismic shoot were promising, and three wells targeting the Wilcox are planned during early 2008.

Vicksburg Trend. Our non-operated holdings in the Vicksburg and Frio Trends are concentrated primarily in the South Midway field in San Patricio County, Texas and the Agua Dulce field. During 2005, we drilled or participated in eleven new wells targeting multiple gas productive sands in the Vicksburg and Frio Formations at depths between 10,000 and 14,500 feet. Results from this program encouraged us to drill seven wells in South Midway and one well in Agua Dulce during 2006 and to participate in the drilling of five additional wells in South Midway during 2007. In 2008, we plan to participate in three more wells in these fields.

Michigan Region

As of December 31, 2007, our estimated proved reserves in the Michigan region were 12.3 MMBOE (32% oil), and our December 2007 daily production averaged 3.5 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. These plants are in good mechanical condition and capable of handling additional production. The West Branch Plant gathers production from the Clayton, West Branch and other smaller fields.

Antrim Production. In northern Michigan, we own an interest in over 50 multi-well Antrim Shale gas projects with proved producing reserves and ongoing development drilling. During 2007, we participated in the drilling and completion of 19 Antrim Shale wells. In 2008, we plan to continue to pursue similar development drilling opportunities.

Clayton Unit. Clayton Unit production is primarily from the Prairie du Chien and Glenwood at a depth of around 11,000 feet. During late 2005, we drilled two Glenwood/Prairie du Chien ("PdC") wells in the Clayton Unit. The target reservoir was the upper PdC, which historically had been the pay interval in the field. Both of these wells encountered hydrocarbons in the Middle interval of the PdC, which had not previously produced. The initial completion in both of these wells was in the middle PdC and both wells still have the original target reservoir behind pipe. We have been encouraged by the results. We have an eight well commitment with the drilling contractor and we are just finishing up well number six. In Missaukee, Oseceola and Clare Counties, Michigan, we are in the process of permitting and shooting a 37 square mile 3-D seismic shoot prospecting for additional PdC and Glenwood accumulations. This data acquisition should be complete by second quarter 2008 and lead to additional drilling later in the year.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2007 by state. Net acreage is our percentage ownership of gross acreage. Acreage in which our interest is limited to royalty and overriding royalty interests is excluded.

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	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
California	35,698	10,707	2,333	50	38,031	10,757
Colorado	34,852	17,285	35,266	8,455	70,118	25,740
Louisiana	40,143	10,589	4,863	2,532	45,006	13,121
Michigan	140,331	61,462	32,524	25,869	172,855	87,331
Montana	40,161	13,183	41,814	19,622	81,975	32,805
North Dakota	188,550	99,777	327,868	188,377	516,418	288,154
Oklahoma	79,569	51,400	2,692	2,317	82,261	53,717
Texas	234,079	141,490	76,110	61,118	310,189	202,608
Utah	20,237	11,497	221,117	48,067	241,354	59,564
Wyoming	105,205	55,961	70,045	44,378	175,250	100,339
Other*	15,898	8,296	1,070	786	16,968	9,082
Total	934,723	481,647	815,702	401,571	1,750,425	883,218

* Other includes Alabama, Arkansas, Mississippi, Nebraska and New Mexico.

Production History

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

	Year Ended December 31,		
	2007	2006	2005
Oil production (MMbbls)	9.6	9.8	7.0
Natural gas production (Bcf)	30.8	32.1	30.3
Total production (MMBOE)	14.7	15.2	12.1
Daily production (MBOE/d)	40.3	41.5	33.1
Average sales prices:			
Oil (per Bbl)	$ 64.57	$ 57.27	$ 51.26
Effect of oil hedges on average price (per Bbl)	(2.21)	(0.95)	(2.72)
Oil net of hedging (per Bbl)	$ 62.36	$ 56.32	$ 48.54
Natural gas (per Mcf)	$ 6.19	$ 6.59	$ 7.03
Effect of natural gas hedges on average price (per Mcf)	-	0.06	(0.47)
Natural gas net of hedging (per Mcf)	$ 6.19	$ 6.65	$ 6.56
Per BOE data:			
Sales price (net of hedging)	$ 53.57	$ 50.52	$ 44.70
Lease operating expenses	$ 14.20	$ 12.12	$ 9.24
Production taxes	$ 3.56	$ 3.11	$ 2.99
Depreciation, depletion and amortization expenses	$ 13.11	$ 10.74	$ 8.08
General and administrative expenses	$ 2.66	$ 2.49	$ 2.53

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Productive Wells

The following table presents our ownership at December 31, 2007 in productive oil and gas wells by region (a net well is our percentage ownership of a gross well).

	Oil Wells		Natural Gas Wells		Total Wells(1)	
	Gross	Net	Gross	Net	Gross	Net
Permian Basin	3,646	1,778	374	131	4,020	1,909
Rocky Mountains	1,711	406	405	199	2,116	605
Mid-Continent	470	312	211	93	681	405
Gulf Coast	93	56	436	129	529	185
Michigan	81	57	1,031	404	1,112	461
Total	6,001	2,609	2,457	956	8,458	3,565

(1) 168 wells are multiple completions. These 168 wells contain a total of 365 completions. One or more completions in the same bore hole are counted as one well

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. The information 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 or economic value. Productive wells are those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonable rate of return.

	Gross Wells			Net Wells		
	Productive	Dry	Total	Productive	Dry	Total
2007:						
Development	262	5	267	128.6	3.8	132.4
Exploratory	9	1	10	6.1	0.1	6.2
Total	271	6	277	134.7	3.9	138.6
2006:						
Development	401	14	415	300.6	9.0	309.6
Exploratory	17	5	22	10.2	2.3	12.5
Total	418	19	437	310.8	11.3	322.1
2005:						
Development	276	18	294	164.7	10.6	175.3
Exploratory	7	7	14	1.3	3.9	5.2
Total	283	25	308	166.0	14.5	180.5

Item 3. Legal Proceedings

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

Item 4. Submission of Matters to a Vote of Security Holders

No matters were submitted to a vote of security holders during the fourth quarter of 2007.

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EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 15, 2008, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	61	Chairman, President and Chief Executive Officer
James T. Brown	55	Senior Vice President, Operations
Bruce R. DeBoer	55	Vice President, General Counsel and Corporate Secretary
Heather M. Duncan	37	Vice President, Human Resources
J. Douglas Lang	58	Vice President, Reservoir Engineering/Acquisitions
Rick A. Ross	49	Vice President, Operations
David M. Seery	53	Vice President, Land
Michael J. Stevens	42	Vice President and Chief Financial Officer
Mark R. Williams	51	Vice President, Exploration and Development
Brent P. Jensen	38	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. Mr. Volker was co-founder, Vice President and later President of Energy Management Corporation from 1971 through 1982. He has over thirty 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 of Operations. Mr. Brown has over thirty 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.

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 over 20 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 over eleven 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 Professional in Human Resources.

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/ Acquisitions in October 2004. His over thirty 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 over 25 years of oil and gas experience. Mr. Ross holds a Bachelor of Science Degree in Mechanical Engineering from the South Dakota School of Mines and Technology.

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 twenty-five years of land experience including staff and managerial positions with Marathon Oil Company. Mr. Seery holds a Bachelor of Science Degree in Business Management from the University of Montana. He is a Registered Land Professional and held various duties with the Denver Association of Petroleum Landmen.

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. From 1993 until May 2001, he served 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.

Mark R. Williams joined us in December 1983 as Exploration Geologist, becoming Vice President of Exploration and Development in December 1999. He has twenty-four years of experience in the oil and gas industry and his areas of primary technical expertise are in sequence stratigraphy, seismic interpretation and petroleum economics. Mr. Williams is a graduate of the Colorado School of Mines with a Master’s Degree in geology and holds a Bachelor’s Degree in geology from the University of Utah.

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 fourteen years of oil and gas accounting experience and is a Certified Public Accountant. Mr. Jensen holds a Bachelor of Arts degree with an emphasis in accounting and business 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.

PART II

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

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

	High	Low
Fiscal Year Ended December 31, 2007		
Fourth Quarter (Ended December 31, 2007)	$ 59.06	$ 44.09
Third Quarter (Ended September 30, 2007)	$ 45.14	$ 35.85
Second Quarter (Ended June 30, 2007)	$ 47.50	$ 38.71
First Quarter (Ended March 31, 2007)	$ 46.04	$ 35.81
Fiscal Year Ended December 31, 2006		
Fourth Quarter (Ended December 31, 2006)	$ 50.30	$ 35.81
Third Quarter (Ended September 30, 2006)	$ 48.10	$ 37.30
Second Quarter (Ended June 30, 2006)	$ 46.95	$ 33.70
First Quarter (Ended March 31, 2006)	$ 47.25	$ 37.41

On February 15, 2008, there were 869 holders of record of our common stock.

We have not paid any dividends since we were incorporated in July 2003. We do not anticipate paying any cash 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. In addition, the agreements governing our indebtedness prohibit us from paying dividends.

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.

We completed our initial public offering in November 2003. Our common stock began trading on the New York Stock Exchange on November 20, 2003. The following graph compares on a cumulative basis changes since November 20, 2003 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 November 20, 2003 in our common stock, the Standard & Poor's Composite 500 Index and the Dow Jones US Oil Companies, Secondary Index.

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	11/20/03	12/31/03	12/31/04	12/31/05	12/31/06	12/31/07
Whiting Petroleum Corporation	$ 100	$ 113	$ 186	$ 246	$ 286	$ 354
Standard & Poor’s Composite 500 Index	100	108	117	121	137	142
Dow Jones US Oil Companies, Secondary Index	100	114	160	263	275	392

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Item 6. Selected Financial Data

The consolidated income statement information for the years ended December 31, 2007, 2006 and 2005 and the consolidated balance sheet information at December 31, 2007 and 2006 are derived from our audited financial statements included elsewhere in this report. The consolidated income statement information for the years ended December 31, 2004 and 2003 and the consolidated balance sheet information at December 31, 2005, 2004 and 2003 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: Utah Hingeline, August 29, 2006; Michigan Properties, August 15, 2006; North Ward Estes and Ancillary Properties, October 4, 2005; Postle Properties, August 4, 2005; Limited Partnership Interests, June 23, 2005; Green River Basin, March 31, 2005; Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; Wyoming and Utah, September 30, 2004; Louisiana and Texas, August 16, 2004; Mississippi, November 3, 2004; and additional Permian Basin interest, December 31, 2004.

	Year Ended December 31,				
	2007	2006	2005	2004	2003
	(dollars in millions, except per share data)				
Consolidated Income Statement Information:					
Revenues and other income:					
Oil and natural gas sales	$ 809.0	$ 773.1	$ 573.2	$ 281.1	$ 175.7
Loss on oil and natural gas hedging activities	(21.2)	(7.5)	(33.4)	(4.9)	(8.7)
Gain on sale of oil and gas properties	29.7	12.1	—	1.0	—
Gain on sale of marketable securities	—	—	—	4.8	—
Interest income and other	1.2	1.1	0.6	0.1	0.3
Total revenues and other income	818.7	778.8	540.4	282.1	167.3
Costs and expenses:					
Lease operating	208.9	183.6	111.6	54.2	43.2
Production taxes	52.4	47.1	36.1	16.8	10.7
Depreciation, depletion and amortization	192.8	162.8	97.6	54.0	41.2
Exploration and impairment	37.3	34.5	16.7	6.3	3.2
General and administrative	39.0	37.8	30.6	19.2	13.0
Change in Production Participation Plan liability	8.6	6.2	9.7	1.7	(0.2)
Phantom equity plan (1)	—	—	—	—	10.9
Interest expense	72.5	73.5	42.0	15.9	9.2
Total costs and expenses	611.5	545.5	344.3	168.1	131.2
Income before income taxes and cumulative change in accounting principle	207.2	233.3	196.1	114.0	36.1
Income tax expense	76.6	76.9	74.2	44.0	13.9
Income before cumulative change in accounting principle	130.6	156.4	121.9	70.0	22.2
Cumulative change in accounting principle (2)	—	—	—	—	(3.9)
Net income	$ 130.6	$ 156.4	$ 121.9	$ 70.0	$ 18.3
	$ -	$ -	$ -	$ -	$ 1.18

Income per common share before cumulative change in accounting principle, basic										
Income per common share before cumulative change in accounting principle, diluted	$	-	$	-	$	-	$	-	$	1.18
Net income per common share, basic	$	3.31	$	4.26	$	3.89	$	3.38	$	0.98
Net income per common share, diluted	$	3.29	$	4.25	$	3.88	$	3.38	$	0.98
Other Financial Information:										
Net cash provided by operating activities	$	394.0	$	411.2	$	330.2	$	134.1	$	91.9
Net cash used in investing activities	$	467.0	$	527.6	$	1,126.9	$	524.4	$	47.6
Net cash provided by financing activities	$	77.3	$	116.4	$	805.5	$	338.4	$	4.4
Ratio of earnings to fixed charges (3)		3.65x		4.14x		5.64x		8.01x		4.85x
Capital expenditures	$	519.6	$	552.0	$	1,126.9	$	530.6	$	47.6

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	As of December 31, 2007	2006	2005	2004	2003
	(dollars in millions)				
Consolidated Balance Sheet Information:					
Total assets	$ 2,952.0	$ 2,585.4	$ 2,235.2	$ 1,092.2	$ 536.3
Total debt	$ 868.2	$ 995.4	$ 875.1	$ 328.4	$ 188.0
Stockholders' equity	$ 1,490.8	$ 1,186.7	$ 997.9	$ 612.4	$ 259.6

(1) The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan, pursuant to which our employees received payments valued at $10.9 million in the form of shares of our common stock. The phantom equity plan is now terminated.

(2) In 2003, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. This was a one-time charge to net income.

(3) For the purpose of calculating the ratio of earnings to fixed charges, earnings consist of income before income taxes and income from equity investees, plus fixed charges, distributed income from equity investees, and amortization of capitalized interest, less capitalized interest. Fixed charges consist of interest expensed, interest capitalized, amortized premiums, discounts and capitalized expenses related to indebtedness, and an estimate of interest within rental expense.

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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 operating subsidiaries, Whiting Oil and Gas Corporation, Equity Oil Company 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 oil and gas 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. During 2004 and 2005, we emphasized the acquisition of properties that provided additional volumes to our current production levels as well as upside potential through further development. During 2006 and 2007, we have focused our drilling activity on the development of these acquired properties, specifically on projects that we believe provide repeatable successes in particular fields. Our combination of acquisitions and subsequent development allows us to direct our capital resources to what we believe to be the most advantageous investments.

While historically we have grown through acquisitions, 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 an increasing percentage of our capital budget to leasing and testing new areas.

We have historically acquired operated and non-operated properties that meet or 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 sale price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

Our revenue, profitability and future growth rate depend on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or gas could materially and adversely affect our financial position, cash flows, results of operations, access to capital, and the quantities of oil and gas reserves that we can economically produce.

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2007 Highlights and Future Considerations

On July 3, 2007, we completed a public offering of our common stock under our existing shelf registration statement, selling 5,425,000 shares of common stock at a price of $40.50 per share, providing net proceeds of $210.4 million, which we used to repay a portion of the debt outstanding under our credit agreement. The number of shares includes the sale of 425,000 shares pursuant to the exercise of the underwriters' overallotment option.

We continue to have significant development and related infrastructure activity on the Postle and North Ward Estes fields acquired in 2005, which has resulted in reserve and production increases. During 2007, we incurred $284.9 million of exploration and development expenditures on these two projects. We expect to incur total future development costs of $625.2 million in the North Ward Estes field and $258.7 million in the Postle field.

Our expansion of the CO2 flood at the Postle field, located in Texas County, Oklahoma, is generating positive results. In December 2007, net production from the field averaged 5.8 MBOE/d. By the end of January 2008, we were injecting over 120 MMcf/d of CO2 into the Morrow formation, the field's producing reservoir.

In 2007, we initiated our CO2 flood in the North Ward Estes field, located in Ward and Winkler Counties, Texas. By the end of January 2008, we were injecting approximately 120 MMcf/d of CO2 into the Yates formation, the field's primary producing reservoir. We expect an initial response from this CO2 flood during the fourth quarter of 2008. Net production from North Ward Estes in December 2007 averaged 5.1 MBOE/d.

Our Robinson Lake prospect in Mountrail County, North Dakota encompasses 118,348 gross acres (83,033 net acres), on which we plan to drill 30 to 40 operated Middle Bakken wells during 2008. The Peery State 11-25H, our discovery well on the Robinson Lake prospect, was completed in May 2007 in the Middle Bakken formation, and was producing 0.3 MBOE/d at the end of January 2008. We completed the Locken 11-22H well in December 2007, which averaged 0.9 MBOE/d during the first 30 days of production. In January 2008, we completed the Liffrig 11-27H well, which averaged 1.1 MBOE/d during the first 30 days of production. We are the operators on these three wells and have three drilling rigs and one workover rig working full time at Robinson Lake, with plans to add a fifth rig in March 2008. By year end 2008, we could have as many as nine drillings rigs working in this prospect.

In December 2007, we began construction of a natural gas processing plant that will separate the natural gas liquids from the natural gas produced from Robinson Lake and allow the natural gas to be transported by pipeline to market. The plant is expected to be operational in the second quarter of 2008. The initial capacity of the plant will be 3.0 MMcf/d, and is expected to increase to approximately 33 MMcf/d by the end of 2008.

Immediately east of the Robinson Lake prospect is the Parshall field, where we have participated in the drilling and completion of 24 wells, 19 of which were drilled in 2007. The initial 15 wells that produced for 120 days had average flow rates of 0.6 MBOE/d per well. We expect to participate in the drilling of approximately 50 to 60 wells in the Parshall field during 2008.

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Another developmental area for us is in the Piceance Basin at the Boies Ranch and Jimmy Gulch properties in Rio Blanco County, Colorado. In the first half of 2007, we drilled and completed three gas producers at Boies Ranch, with each well flowing at an initial rate of 2.3 MMcf/d of gas from the Williams Fork and Iles formations. At year end 2007, there were six wells awaiting completion operations at Boies Ranch and two being drilled, with drilling operations expected to commence at Jimmy Gulch in the third quarter of 2008. We plan to have a minimum of two drilling rigs running full time in the Piceance Basin, drilling approximately 24 wells by the end of 2008.

We are evaluating and engaged in discussions with respect to the potential sale of economic interests in other non-core properties, although we have not made a decision on whether to do so or the form that any such transaction would take. Our intention is to monetize the value of some of our predominantly proved developed producing properties with this potential sale. In November 2007, we filed a registration statement relating to a proposed initial public offering of units of beneficial interest in Whiting USA Trust I. We plan to contribute a term net profits interest in certain of our oil and natural gas properties in exchange for trust units. These property interests had estimated reserves of up to 8.2 MMBOE, as of a January 1, 2008 effective date, representing up to 3.3% of our proved reserves as of December 31, 2007, and 11.5%, or 4.6 MBOE/d, of our December 2007 average daily net production. We intend to use the net proceeds from this offering to repay a portion of the debt outstanding under our credit agreement. The amount of proceeds ultimately received from this offering, and the timing of the completion of this offering, is subject to a variety of factors, including favorable market conditions. We cannot provide any assurance, however, that we will be able to complete this offering or any other form of asset sales.

Although independent engineers estimated probable and possible reserves relating to certain 2006 and prior year producing property acquisitions, we, consistent with our present acquisition practices, have associated substantially all producing property acquisition costs with proved reserves. Because of our substantial acquisition activity, our discussion and analysis of our historical financial condition and results of operations for the periods discussed below may not necessarily be comparable with or applicable to our future results of operations. Our historical results include the results from our recent acquisitions beginning on the following dates: Utah Hingeline, August 29, 2006; Michigan Properties, August 15, 2006; North Ward Estes and Ancillary Properties, October 4, 2005; Postle Properties, August 4, 2005; Limited Partnership Interests, June 23, 2005; and Green River Basin, March 31, 2005.

Acquisitions

Utah Hingeline. On August 29, 2006, we acquired a 15% working interest in approximately 170,000 acres of unproved properties in the central Utah Hingeline play for $25.0 million. No producing properties or proved reserves were associated with this acquisition. As part of this transaction, the operator agreed to pay 100% of our drilling and completion costs for the first three wells in the project.

Michigan Properties. On August 15, 2006, we acquired 65 producing properties, a gathering line, gas processing plant and 30,437 net acres of leasehold held by production in Michigan. The purchase price was $26.0 million for estimated proved reserves of 1.4 MMBOE as of the acquisition effective date of May 1, 2006, resulting in a cost of $18.55 per BOE of estimated proved reserves. Proved developed reserve quantities represented 99% of the total proved reserves acquired. The average daily production from the properties was 0.6 MBOE/d as of the acquisition effective date. We operate 85% of the acquired properties.

North Ward Estes and Ancillary Properties. On October 4, 2005, we acquired the operated interest in the North Ward Estes field in Ward and Winkler counties, Texas, and certain smaller fields located in the Permian Basin. The purchase price was $459.2 million, consisting of $442.0 million in cash and 441,500 shares of our common stock, for estimated proved reserves of 82.1 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of $5.58 per BOE of estimated proved reserves. Proved developed reserve quantities represented 36% of the total proved reserves acquired. The average daily production from the properties was 4.6 MBOE/d as of the acquisition effective date. We funded the cash portion of the purchase price with the net proceeds from a public offering of common stock and a private placement of 7% Senior Subordinated Notes due 2014.

Postle Properties. On August 4, 2005, we acquired the operated interest in producing oil and gas fields located in the Oklahoma Panhandle. The purchase price was $343.0 million for estimated proved reserves of 40.3 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of $8.52 per BOE of estimated proved reserves. The average daily production from the properties was 4.2 MBOE/d as of the acquisition effective date. Proved developed reserve quantities represented 57% of the total proved reserves acquired. We funded the acquisition through borrowings under our credit agreement.

Limited Partnership Interests. On June 23, 2005, we acquired all of the limited partnership interests in three institutional partnerships managed by our wholly-owned subsidiary Whiting Programs, Inc. The partnership properties were located in Louisiana, Texas, Arkansas, Oklahoma and Wyoming. The purchase price was $30.5 million for estimated proved reserves of 2.9 MMBOE as of the acquisition effective date of January 1, 2005, resulting in a cost of $10.52 per BOE of estimated proved reserves. Proved developed reserve quantities represented 99% of the total proved reserves acquired. The average daily production from the properties was 0.7 MBOE/d as of the acquisition effective date. We funded the acquisition with cash on hand.

Green River Basin. On March 31, 2005, we acquired operated interests in five producing gas fields in the Green River Basin of Wyoming. The purchase price was $65.0 million for estimated proved reserves of 8.4 MMBOE as of the acquisition effective date of March 1, 2005, resulting in a cost of $7.74 per BOE of estimated proved reserves. Proved developed reserve quantities represented 68% of the total proved reserves acquired. The average daily production from the properties was 1.1 MBOE/d as of the acquisition effective date. We funded the acquisition though borrowings under our credit agreement and with cash on hand.

Divestitures

On July 17, 2007, we sold our approximate 50% non-operated working interest in several gas fields located in the LaSalle and Webb Counties of Texas for total cash proceeds of $40.1 million, resulting in a pre-tax gain on sale of $29.7 million. The divested properties had estimated proved reserves of 2.3 MMBOE as of December 31, 2006, adjusted to the July 1, 2007 divestiture effective date, thereby yielding a sale price of $17.77 per BOE. The June 2007 average daily net production from these fields was 0.8 MBOE/d.

During 2007, we sold our interests in several non-core properties for an aggregate amount of $12.5 million in cash for total estimated proved reserves of 0.6 MMBOE as of the divestitures' effective dates, or $18.82 per BOE. No gain or loss was recognized on the sales. These properties are located in Colorado, Louisiana, Michigan, Montana, New Mexico, North Dakota, Oklahoma, Texas and Wyoming. The average daily net production from the divested property interests was 0.3 MBOE/d as of the dates of disposition.

During 2006, we sold our interests in several non-core properties for an aggregate amount of $24.4 million in cash for total estimated proved reserves of 1.4 MMBOE as of the divestitures' effective dates. The divested properties included interests in the Cessford field in Alberta, Canada; Permian Basin of West Texas and New Mexico; and the Ashley Valley field in Uintah County, Utah. The average net production from the divested property interests was 0.4 MBOE/d as of the dates of disposition, and we recognized a pre-tax gain on sale of $12.1 million related to these divestitures.

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Results of Operations

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

	Year Ended December 31,		
	2007	2006	2005
Net production:			
Oil (MMbbls)	9.6	9.8	7.0
Natural gas (Bcf)	30.8	32.1	30.3
Total production (MMBOE)	14.7	15.2	12.1
Net sales (in millions):			
Oil (1)	$ 618.5	$ 561.2	$ 360.4
Natural gas (1)	190.5	211.9	212.8
Total oil and natural gas sales	$ 809.0	$ 773.1	$ 573.2
Average sales prices:			
Oil (per Bbl)	$ 64.57	$ 57.27	$ 51.26
Effect of oil hedges on average price (per Bbl)	(2.21)	(0.95)	(2.72)
Oil net of hedging (per Bbl)	$ 62.36	$ 56.32	$ 48.54
Average NYMEX price	$ 72.30	$ 66.25	$ 56.61
Natural gas (per Mcf)	$ 6.19	$ 6.59	$ 7.03
Effect of natural gas hedges on average price (per Mcf)	-	0.06	(0.47)
Natural gas net of hedging (per Mcf)	$ 6.19	$ 6.65	$ 6.56
Average NYMEX price	$ 6.86	$ 7.23	$ 8.64
Cost and expense (per BOE):			
Lease operating expenses	$ 14.20	$ 12.12	$ 9.24
Production taxes	$ 3.56	$ 3.11	$ 2.99
Depreciation, depletion and amortization expense	$ 13.11	$ 10.74	$ 8.08
General and administrative expenses	$ 2.66	$ 2.49	$ 2.53

(1) Before consideration of hedging transactions.

Year Ended December 31, 2007 Compared to Year Ended December 31, 2006

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $35.9 million to $809.0 million in 2007 compared to 2006. Sales are a function of volumes sold and average sales prices. Our oil sales volumes decreased 2% and our gas sales volumes decreased 4% between periods. The volume declines resulted in part from property sales, production shut-ins due to delays at third-party refineries, and normal field production decline, which factors were partially offset by production increases from development activities. Our 2007 and 2006 property divestitures resulted in a decline of approximately 317 MBOE, 48% of which related to natural gas. Approximately 34 MBOE of production from the Postle field was shut-in or restricted from February 19 through March 8, 2007 due to a fire at a third-party refinery, and approximately 32 MBOE of production from the Boies Ranch field was restricted from July 28 to November 18, 2007 due to repairs at the field's gas processing plant. During 2007, we also converted several production wells to injectors at our North Ward Estes field, as the Phase I area of the reservoir was pressured up in preparation for CO2 injection. Our average price for oil before effects of hedging increased 13% and our average price for natural gas before effects of hedging decreased 6% between periods.

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Loss on Oil and Natural Gas Hedging Activities. We hedged 53% of our oil volumes during 2007, incurring derivative settlement losses of $21.2 million, and 54% of our oil volumes during 2006, incurring derivative settlement losses of $9.4 million. We hedged 16% of our gas volumes during 2007, incurring no realized hedging gains or losses, and 59% of our gas volumes during 2006, resulting in derivative settlement gains of $1.9 million. See Item 7A, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil hedges as of January 1, 2008.

Gain on Sale of Properties. During 2007, we sold our interests in several non-core properties for an aggregate amount of $52.6 million in cash, resulting in a pre-tax gain on sale of $29.7 million. During 2006, we sold our interests in several non-core properties for an aggregate amount of $24.4 million in cash and recognized a pre-tax gain on sale of $12.1 million.

Lease Operating Expenses. Our 2007 lease operating expenses were $208.9 million, a $25.2 million increase over 2006. Our lease operating expense as a percentage of oil and gas sales increased from 24% during 2006 to 26% during 2007, and our lease operating expenses per BOE increased from $12.12 during 2006 to $14.20 during 2007. The increase of 17% on a BOE basis was primarily caused by a high level of workover activity, inflation in the cost of oil field goods and services, and a change in labor billing practices. Workovers amounted to $17.4 million in 2007, as compared to $8.9 million of workover activity during 2006. The cost of oil field goods and services increased due to a higher demand in the industry. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to Council of Petroleum Accountants Societies ("COPAS") guidelines. This change in labor billing practices resulted in lower net general and administrative expense and higher amounts of lease operating expense being charged to us and our joint interest owners on properties we operate.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for 2007 and 2006 were 6.5% and 6.1%, respectively, of oil and gas sales. The 2007 rate was greater than the 2006 rate due to the change in property mix associated with recent divestitures in low tax jurisdictions and drilling successes in higher tax jurisdictions.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased $30.0 million to $192.8 million during 2007, as compared to $162.8 million for the same period in 2006. On a BOE basis, our DD&A rate increased from $10.74 during 2006 to $13.11 in 2007. The primary factors causing this rate increase were (1) $529.3 million in drilling expenditures incurred during the past 12 months in relation to net oil and gas reserve additions over the same time period, and (2) the significant expenditures necessary to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields, whereby the development of proved undeveloped reserves does not increase existing quantities of proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31, 2007	2006
Depletion	$ 186,838	$ 157,868
Depreciation	3,123	2,675
Accretion of asset retirement obligations	2,850	2,288
Total	$ 192,811	$ 162,831

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Exploration and Impairment Costs. Our exploration and impairment costs increased $2.8 million in 2007 as compared to 2006. The components of exploration and impairment costs were as follows (in thousands):

	Year Ended December 31, 2007	2006
Exploration	$ 27,344	$ 30,079
Impairment	9,979	4,455
Total	$ 37,323	$ 34,534

During 2007, we participated in a non-operated exploratory well drilled in the Gulf Coast region that resulted in an insignificant amount of dry hole expense. In 2006, we drilled three exploratory dry holes in the Rocky Mountains region, one exploratory dry hole in the Gulf Coast region and one exploratory dry hole in the Mid-Continent region, totaling $7.2 million. This reduction in exploratory dry hole expense was partially offset by an increase in geological and geophysical ("G&G") activity during 2007. G&G costs amounted to $15.7 million during 2007, as compared to $12.2 million in 2006. Impairment charges in 2007 and 2006 relate to the amortization of leasehold costs associated with individually insignificant unproved properties. The increase in impairment of $5.5 million is due to an additional $35.1 million of unproved property costs being amortized during the year ended December 31, 2007, as compared to the same period in 2006.

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, 2007	2006
General and administrative expenses	$ 72,008	$ 60,972
Reimbursements and allocations	(32,962)	(23,164)
General and administrative expenses, net	$ 39,046	$ 37,808

General and administrative expenses before reimbursements and allocations increased $11.0 million to $72.0 million during 2007. The largest components of the increase related to $7.5 million of additional salaries and wages for personnel hired during the past twelve months and $2.9 million in incremental distributions under our Production Participation Plan, attributable primarily to the Company's 2007 oil and gas property divestitures. The increase in reimbursements and allocations in 2007 was caused by increased salary expenses and a higher number of field workers on operated properties. In addition during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. These changes in labor billing practices resulted in higher reimbursements and allocations and, therefore, higher amounts of lease operating expense being allocated to us and charged to our joint interest owners on properties we operate. Our net general and administrative expenses as a percentage of oil and gas sales remained consistent at 5% for both 2007 and 2006.

Change in Production Participation Plan Liability. For the year ended December 31, 2007, this non-cash expense increased $2.4 million to $8.6 million. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2008 under our Production Participation Plan ("Plan"). Although payments take place over the life of the Plan's oil and gas properties, which for some properties is over 20 years, we must expense the present value of estimated future payments over the Plan's five year vesting period. This expense in 2007 and 2006 primarily reflects changes to future cash flow estimates and related Plan liability due to the effect of a sustained higher price environment, recent drilling activity and employees' continued vesting in the Plan. For the year ended December 31, 2007, the five-year average historical NYMEX prices used to estimate this liability increased $8.58 for crude oil and $0.67 for natural gas, as compared to increases of $7.40 for crude oil and $0.52 for natural gas for the year ended December 31, 2006. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

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

	Year Ended December 31, 2007	2006
Credit Agreement	$ 24,428	$ 21,478
Senior Subordinated Notes	44,691	44,530
Amortization of debt issue costs and debt discount	5,022	5,208
Accretion of tax sharing liability	1,505	2,016
Other	522	813
Capitalized interest	(3,664)	(556)
Total interest expense	$ 72,504	$ 73,489

The decrease in interest expense was due to increased capitalized interest on the construction and expansion of processing facilities. This decrease was partially offset by increased interest expense on our credit agreement as a result of additional borrowings outstanding in 2007, as well as higher weighted average interest rates on our debt during 2007.

Our weighted average debt outstanding during 2007 was $964.4 million versus $945.3 million during 2006. Our weighted average effective cash interest rate was 7.2% during 2007 versus 7.0% during 2006. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 7.7% during 2007 versus 7.5% during 2006.

Income Tax Expense. Income tax expense totaled $76.6 million for 2007 and $76.9 million for 2006. Our effective income tax rate increased from 33.0% for 2006 to 37.0% for 2007. Our effective income tax rate was higher for 2007 primarily due to several non-recurring benefits recognized in 2006 consisting of: a $4.3 million deferred tax benefit for 2005 enhanced oil recovery (“EOR”) tax credits; a $2.3 million benefit relating to a true-up of our effective tax rate to our 2005 state returns as filed; and deferred tax benefits of $1.2 million as a result of state tax legislation enacted in 2006. In addition, we incurred incremental income tax of $1.5 million during 2007 relating to an adjustment of prior year’s tax expense upon filing our 2006 returns. This expense was partially offset by a $0.6 million net deferred tax benefit recognized in 2007 for EOR credits relating to 2003 and 2004.

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. Federal EOR credits are subject to phase-out according to the level of average domestic crude prices. Due to recent high oil prices, the EOR credit was phased-out for 2007 and 2006.

The current portion of income tax expense was $0.6 million for 2007 compared to $12.3 million in 2006. We expect to report a net operating loss in our 2007 returns, mainly due to intangible drilling deductions allowed.

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Net Income. Net income decreased from $156.4 million in 2006 to $130.6 million for 2007. The primary reasons for this decrease include a 3% decrease in equivalent volumes sold, a 7% decrease in gas prices (net of hedging) between periods, higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative expenses, and change in Production Participation Plan liability. The decreased production and gas prices and increased expenses were partially offset by an 11% increase in oil prices (net of hedging) between periods, a higher gain on sale of properties, and lower interest expense and income taxes in 2007.

Year Ended December 31, 2006 Compared to Year Ended December 31, 2005

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased $199.9 million to $773.1 million in 2006 as compared to 2005. Sales are a function of volumes sold and average sales prices. Our oil sales volumes increased 39% and our gas sales volumes increased 6% between periods. The volume increases resulted from acquisitions completed in 2005 and 2006 and successful drilling activities during 2006, which produced new sales volumes that more than offset normal field production decline. Our average price for oil before effects of hedging increased 12% and our average price for natural gas before effects of hedging decreased 6% between periods.

Loss on Oil and Natural Gas Hedging Activities. We hedged 54% of our oil volumes during 2006, incurring derivative settlement losses of $9.4 million, and 58% of our oil volumes during 2005, incurring derivative settlement losses of $19.1 million. We hedged 59% of our gas volumes during 2006 incurring derivative settlement gains of $1.9 million, and 60% of our gas volumes during 2005, incurring derivative settlement losses of $14.3 million.

Gain on Sale of Properties. During 2006, we sold our interests in several non-core properties for an aggregate amount of $24.4 million in cash and recognized a pre-tax gain on sale of $12.1 million. The divested properties included interests in the Cessford field in Alberta, Canada; Permian Basin of West Texas and New Mexico; and the Ashley Valley field in Uintah County, Utah. There was no gain or loss on sale of properties during 2005.

Lease Operating Expenses. Our lease operating expenses increased $72.1 million to $183.6 million in 2006 as compared to 2005. The increase resulted primarily from costs associated with new property acquisitions during 2005 and 2006 and successful drilling activities during 2006. Our lease operating expense as a percentage of oil and gas sales increased from 19% during 2005 to 24% during 2006. Our lease operating expenses per BOE increased from $9.24 during 2005 to $12.12 during 2006. The increase of 31% on a BOE basis was primarily caused by inflation in the cost of oil field goods and services, a high level of workover activity on recently acquired properties, increased costs related to tertiary recovery projects, a change in labor billing practices and higher energy costs. Oil field goods and services increased due to a higher demand in the industry. Workovers amounted to $8.9 million in 2006, as compared to $3.9 million of workover activity during 2005. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. This change in labor billing practices resulted in lower net general and administrative expense and higher amounts of lease operating expense being charged to us and our joint interest owners on properties we operate.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in our various taxing jurisdictions. Our production taxes for 2006 and 2005 were 6.1% and 6.3%, respectively, of oil and gas sales. The 2006 rate was lower than the 2005 rate due to the change in property mix associated with recent acquisitions.

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Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased $65.2 million to $162.8 million during 2006, as compared to $97.6 million for 2005. The increase resulted from higher production volumes in 2006 and an increase in our DD&A rate. On a BOE basis, our DD&A rate increased from $8.08 during 2005 to $10.74 in 2006. The primary factors causing this rate increase were higher drilling expenditures, downward oil and gas reserve revisions, and an increased level of expenditures to develop proved undeveloped reserves, particularly related to the enhanced oil recovery projects in the Postle and North Ward Estes fields where the development of undeveloped reserves does not increase existing proved reserves. Under the successful efforts method of accounting, costs to develop proved undeveloped reserves are added into the DD&A rate when incurred. Also contributing to our higher DD&A rate was the association of all 2005 property acquisition costs with proved reserves and none with unproved reserves, thereby including all such costs in our DD&A rate immediately when incurred. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2006	2005
Depletion	$ 157,868	$ 93,818
Depreciation	2,675	1,457
Accretion of asset retirement obligations	2,288	2,364
Total	$ 162,831	$ 97,639

Exploration and Impairment Costs. Our exploration and impairment costs increased $17.8 million to $34.5 million in 2006 compared to 2005. The components of our exploration and impairment costs were as follows (in thousands):

	Year Ended December 31,	
	2006	2005
Exploration	$ 30,079	$ 14,665
Impairment	4,455	2,034
Total	$ 34,534	$ 16,699

Higher exploration costs resulted from three exploratory dry holes drilled in the Rocky Mountains region, one exploratory dry hole drilled in the Gulf Coast region and one exploratory dry hole drilled in the Mid-Continent region in 2006, totaling $7.2 million. In 2005, we drilled a total of seven exploratory dry holes, totaling $4.0 million. We incurred $12.2 million in geological and geophysical expenses during 2006, up $7.4 million from 2005. We also hired additional exploration personnel to support the increased drilling budget from $223.6 million in 2005 to $455.0 million in 2006, resulting in an additional $4.0 million of exploration expense. The impairment charge in 2006 consisted of $3.7 million in amortized leasehold costs associated with individually insignificant unproved properties and $0.8 million in proved property impairments. The impairment charge in 2005 related to unrecoverable costs associated with our investment in the Cherokee Basin in Kansas.

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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,	
	2006	2005
General and administrative expenses	$ 60,972	$ 42,594
Reimbursements and allocations	(23,164)	(11,987)
General and administrative expenses, net	$ 37,808	$ 30,607

General and administrative expenses before reimbursements and allocations increased $18.4 million to $61.0 million during 2006. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $13.6 million and an increase in the 2006 accrual for cash payments under our Production Participation Plan of $3.6 million. Personnel salary expenses were higher in 2006 due to an increase in our employee base resulting from our continued growth. The increased cost of the Production Participation Plan was caused primarily by higher 2006 production volumes and higher average sales prices on crude oil between years. The increase in reimbursements and allocations in 2006 was caused by increased salary expenses and a higher number of field workers on operated properties, due to recent acquisitions and drilling activities during 2006. In addition, during the fourth quarter of 2006, we revised our labor billing practices to better conform to COPAS guidelines. This change in labor billing practices resulted in higher reimbursements and allocations and, therefore, higher amounts of lease operating expense being charged to us and our joint interest owners on properties we operate. Our net general and administrative expenses as a percentage of oil and gas sales remained consistent at 5% for both 2006 and 2005.

Change in Production Participation Plan Liability. For the year ended December 31, 2006, this non-cash expense decreased by $3.5 million to $6.2 million. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2007 under our Production Participation Plan (“Plan”). Although payments take place over the life of oil and gas properties contributed to the Plan, which for some properties is over 20 years, we must expense the present value of estimated future payments over the Plan’s five year vesting period. This expense in 2006 and in 2005 primarily reflects changes to future cash flow estimates and related Plan liability due to the effect of a sustained higher price environment, recent drilling activity, and employees’ continued vesting in the Plan. For the year ended December 31, 2006, the five-year average historical NYMEX prices used to estimate this liability increased $7.40 for crude oil and $0.52 for natural gas, as compared to increases in PPP pricing utilized of $15.01 for crude oil and $2.75 for natural gas for the year ended December 31, 2005. Assumptions that are used to calculate this liability are subject to estimation and will vary from year to year based on the current market for oil and gas, discount rates and overall market conditions.

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

	Year Ended December 31,	
	2006	2005
Credit Agreement	$ 21,478	$ 9,997
Senior Subordinated Notes	44,530	25,109
Amortization of debt issue costs and debt discount	5,208	4,076
Accretion of tax sharing liability	2,016	2,725
Other	813	138
Capitalized interest	(556)	-
Total interest expense	$ 73,489	$ 42,045

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The increases in interest expense and amortization of debt issue costs and debt discount were mainly due to the April 2005 issuance of $220.0 million 7.25% Senior Subordinated Notes due 2013, the October 2005 issuance of $250.0 million 7% Senior Subordinated Notes due 2014, and additional borrowings outstanding in 2006 under our credit agreement. We also experienced higher weighted average interest rates on our debt during 2006.

Our weighted average debt outstanding during 2006 was $945.3 million versus $553.0 million during 2005. Our weighted average effective cash interest rate was 7.0% during 2006 versus 6.4% during 2005. After inclusion of non-cash interest costs related to the amortization of debt issue costs and debt discount and the accretion of the tax sharing liability, our weighted average effective all-in interest rate was 7.5% during 2006 versus 7.2% during 2005.

Income Tax Expense. Income tax expense totaled $76.9 million for 2006 and $74.2 million for 2005. Our effective income tax rate decreased from 37.8% for 2005 to 33.0% for 2006. Our effective income tax rate was higher for 2006 primarily due to several non-recurring benefits recognized in 2006 consisting of: a $4.3 million deferred tax benefit for 2005 enhanced oil recovery (“EOR”) tax credits; a $2.3 million benefit relating to a true-up of our effective tax rate to our 2005 state returns as filed; and deferred tax benefits of $1.2 million as a result of state tax legislation enacted in 2006.

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. Federal EOR credits are subject to phase-out according to the level of average domestic crude prices. Due to recent high oil prices, the EOR credit was phased-out for 2006.

The current portion of income tax expense was $12.3 million for 2006 compared to $8.5 million in 2005. In 2006, we reported a tax loss on our 2005 federal return, primarily due to intangible drilling deductions allowed, which resulted in a federal tax refund of $4.7 million.

Net Income. Net income increased from $121.9 million in 2005 to $156.4 million for 2006. The primary reasons for this increase included a 26% increase in equivalent volumes sold, a 14% increase in oil and gas prices net of hedging between periods, certain income tax benefits recognized during 2006 and a gain on sale of oil and gas properties. These increases were partially offset by higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative and interest expenses in 2006 resulting from our continued growth.

Liquidity and Capital Resources

Overview. At December 31, 2007, our debt to total capitalization ratio was 36.8%, we had $14.8 million of cash on hand and $1,490.8 million of stockholders’ equity. At December 31, 2006, our debt to total capitalization ratio was 45.6%, we had $10.4 million of cash on hand and $1,186.7 million of stockholders’ equity. In 2007, we generated $394.0 million of cash provided by operating activities, a decrease of $17.2 million from 2006. Cash provided by operating activities decreased primarily because of higher operating costs, lower production as a result of our recent dispositions, and lower average sales prices for natural gas, partially offset by higher average sales prices for crude oil. We also generated $77.3 million from financing activities primarily consisting of $210.4 million in net proceeds received from the issuance of our common stock, offset by net repayments under our credit agreement totaling $130.0 million. Cash flows from operating and financing activities, as well proceeds from property divestitures, were primarily used to finance $525.3 million of exploration and development expenditures paid in 2007 and $21.6 million of cash acquisition capital expenditures, including the Parshall Prospect in North Dakota. The following chart details our exploration and development expenditures incurred by region during 2007 (in thousands):

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	Drilling and Development Expenditures	Exploration Expenditures	Total Expenditures	% of Total
Rocky Mountains	$ 179,043	$ 15,199	$ 194,242	35%
Permian Basin	179,715	4,737	184,452	33%
Mid-Continent	131,936	1,819	133,755	24%
Gulf Coast	18,995	4,548	23,543	4%
Michigan	19,613	1,040	20,653	4%
Total incurred	529,302	27,343	556,645	100%
Increase in accrued capital expenditures	(31,314)	-	(31,314)	
Total paid	497,988	27,343	$ 525,331	

We continually evaluate our capital needs and compare them to our capital resources. Our 2008 budgeted exploration and development expenditures for the further development of our property base are $640.0 million, an increase from the $556.6 million incurred on exploration and development expenditures during 2007, primarily due to additional drilling opportunities that have been identified in our Robinson Lake area in the Williston Basin, our Boies Ranch and Jimmy Gulch prospect areas in the Piceance Basin, and other core areas. Although we have no specific budget for property acquisitions in 2008, we will continue to selectively pursue property acquisitions that complement our existing core property base. We expect to fund our 2008 exploration and development expenditures from internally generated cash flow, cash on hand, and borrowings under our credit agreement. We believe that should attractive acquisition opportunities arise or exploration and development expenditures exceed $640.0 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.

Credit Agreement. Our wholly-owned subsidiary, Whiting Oil and Gas Corporation (“Whiting Oil and Gas”) has a $1.2 billion credit agreement with a syndicate of banks that, as of December 31, 2007, had a borrowing base of $900.0 million with $250.0 million in borrowings outstanding, leaving $650.0 million of available borrowing capacity. The borrowing base under the credit agreement is determined at the discretion of the lenders, based on the collateral value of our proved reserves that have been mortgaged to our 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.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas may, throughout the five-year term of the credit agreement, borrow, repay and re-borrow up to the borrowing base in effect at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of ours in an aggregate amount not to exceed $50.0 million. As of December 31, 2007, letters of credit totaling $0.2 million were outstanding under the credit agreement.

Interest accrues at Whiting Oil and Gas' option at either (1) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. We have consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage and are included as a component of interest expense. At December 31, 2007, the effective weighted average interest rate on the outstanding principal balance under the credit agreement was 6.1%. At December 31, 2007, we locked in this LIBOR option at a rate of 5.92% through January 31, 2008. On January 31, 2008, the LIBOR option rate was reset to 4.27% through March 31, 2008.

The credit agreement contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders and requires us to maintain a debt to EBITDAX ratio (as defined in the credit agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and our wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. We were in compliance with our covenants under the credit agreement as of December 31, 2007. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for our guarantee, and Equity Oil Company has mortgaged all of its properties, which are included in the borrowing base for the credit agreement, as security for its guarantee.

Senior Subordinated Notes. In October 2005, we issued at par $250.0 million of 7% Senior Subordinated Notes due 2014.

In April 2005, we issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount is being amortized to interest expense over the term of these notes.

In May 2004, we issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount is being amortized to interest expense over the term of these notes.

The notes are unsecured obligations of ours and are subordinated to all of our senior debt, which currently consists of Whiting Oil and Gas' credit agreement. 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, incur additional indebtedness 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, 2007. Our wholly-owned operating subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company, have fully, unconditionally, jointly and severally guaranteed our obligations under the notes.

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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 following table summarizes our obligations and commitments as of December 31, 2007 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include Production Participation Plan liabilities since we cannot determine with accuracy the timing or amounts of future payments (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)	$ 870,000	$ -	$ 250,000	$ 150,000	$ 470,000
Cash interest expense on debt (b)	300,526	59,460	118,920	84,747	37,399
Asset retirement obligations (c)	37,192	1,309	512	3,263	32,108
Tax sharing liability (d)	25,657	2,587	4,408	3,699	14,963
Derivative contract liability fair value (e)	72,796	72,796	-	-	-
Purchase obligations (f)	367,675	62,887	128,897	120,512	55,379
Drilling rig contracts (g)	56,371	33,916	22,455	-	-
Operating leases (h)	6,225	2,003	3,769	453	-
Total	$ 1,736,442	$ 234,958	$ 528,961	$ 362,674	$ 609,849

(a) Long-term debt consists of the 7.25% Senior Subordinated Notes due 2012 and 2013, the 7% Senior Subordinated Notes due 2014 and the outstanding debt under our credit agreement, and assumes no principal repayment until the due date of the instruments.

(b) Cash interest expense on the 7.25% Senior Subordinated Notes due 2012 and 2013 and the 7% Senior Subordinated Notes due 2014 is estimated assuming no principal repayment until the due date of the instruments. The interest rate swap on the $75.0 million of our $150.0 million fixed rate 7.25% Senior Subordinated Notes due 2012 is assumed to equal 7.2% until the due date of the instrument. Cash interest expense on the credit agreement is estimated assuming no principal repayment until the instrument due date, and a fixed interest rate of 6.1%.

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

(d) 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.

(e) We have entered into derivative contracts, primarily costless collars, to hedge our exposure to crude oil price fluctuations. As of December 31, 2007, the forward price curves for crude oil generally exceeded the price curves that were 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.

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(f) We have two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement expiring in December 2014, whereby we have committed to buy certain volumes of CO_2 for a fixed fee, subject to annual escalation, 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 CO_2 (as calculated on an annual basis) or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. The CO_2 volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, we expect to avoid any payments for deficiencies.

(g) We currently have two drilling rigs under contract through 2008, two drilling rigs through 2009, one drilling rig through 2010, and a workover rig under contract through 2009, all of which are operating in the Rocky Mountains region. As of December 31, 2007, early termination of these contracts would have required maximum penalties of $41.2 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 drilling time remaining on rigs drilling on a well-by-well basis, such obligations have not been included in this table.

(h) We lease 87,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2010, and an additional 30,100 square feet of office space in Midland, Texas through February 15, 2012.

Based on current oil and 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 Policies

In June 2006, the Financial Accounting Standards Board (“FASB”) issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes, an interpretation of Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes (“FIN 48”). The interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

We adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, we recognized a $0.3 million increase in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings and a corresponding increase in other long-term liabilities. Our policy is to recognize interest and penalties accrued related to unrecognized tax benefits within income tax expense.

New Accounting Pronouncements

In September 2006, the FASB issued Statement No. 157, Fair Value Measurements (“SFAS 157”). The adoption of SFAS 157 is not expected to have a material impact on our consolidated financial position, cash flows or results of operations. However, additional disclosures may be required about the information used to develop the measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years.

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In February 2007, the FASB issued Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115 ("SFAS 159"). SFAS 159 expands the use of fair value accounting but does not affect existing standards which require assets or liabilities to be carried at fair value. Under SFAS 159, a company may elect to use fair value to measure many financial instruments and certain other assets and liabilities at fair value. We decided not to elect fair value accounting for any of our eligible items. The adoption of SFAS 159 therefore will have no impact on our consolidated financial position, cash flows or results of operations. If the use of fair value is elected (the fair value option), any upfront costs and fees related to the item must be recognized in earnings and cannot be deferred, e.g., debt issue costs. The fair value election is irrevocable and generally made on an instrument-by-instrument basis, even if a company has similar instruments that it elects not to measure based on fair value. At the adoption date, unrealized gains and losses on existing items for which fair value has been elected are reported as a cumulative adjustment to beginning retained earnings. Subsequent to the adoption of SFAS 159, changes in fair value are recognized in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007.

In December 2007, the FASB issued Statement No. 141R, Business Combinations ("SFAS 141R"). SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in the business combination and determines what information to disclose to enable users of the financial statement to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008. Accordingly, any business combinations we engage in will be recorded and disclosed following existing GAAP until January 1, 2009. We expect SFAS No. 141R will have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions we consummate after the effective date.

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. Our significant accounting policies are 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, all costs associated with property acquisitions, 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 and the Gulf of Mexico.

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Oil and 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 gas properties, asset retirement obligations, and our long-term Production Participation Plan liability. Proved oil and gas reserves are the estimated quantities of crude oil, natural gas and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future periods from known reservoirs under existing economic and operating conditions. 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 proved reserve information included in this report is based on estimates prepared by our independent petroleum engineers, Cawley, Gillespie & Associates, Inc. The independent petroleum engineers evaluated 100% of our estimated proved reserve quantities and their related future net cash flows as of December 31, 2007. 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, reducing our net income. This decline may result from lower commodity prices, which may make it uneconomic to drill for and produce higher cost fields. We are unable to predict changes in reserve quantity estimates as such quantities are dependent on the success of our exploitation and development program, as well as future economic conditions.

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

Asset Retirement Obligation. Our asset retirement obligations (“ARO”) consist 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 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 field.

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 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 Employee Compensation and Benefits" line item in our consolidated balance sheets. This obligation is based on cash flows during the preceding 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 discounted at 12%, which as discussed above, are subject to revision as more information becomes available. Our price assumptions are currently determined using average prices for the preceding five years. Variances between estimates used to calculate liabilities related to the Production Participation Plan and actual sales, cost and reserve 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, 2007 would have decreased net income before taxes by $5.6 million in 2007.

Derivative Instruments and Hedging Activity. We periodically enter into commodity derivative contracts to manage our exposure to oil and gas price volatility. We use hedging to reduce price volatility, help ensure that we have adequate cash flow to fund our capital programs and manage price risks and returns on some of 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 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. All derivative instruments are recorded on the consolidated balance sheet at fair value. Changes in the derivative's 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 oil and natural gas hedging activities" line item in our consolidated statements of income in the period that the hedged production is delivered. Hedge effectiveness is measured at least quarterly based on the relative changes in the fair value between the derivative contract and the hedged item over time. We currently do not have any derivative contracts in place that do not qualify as cash flow hedges.

We have established the fair value of all derivative instruments using estimates determined by our counterparties and subsequently evaluated such fair values internally using established index prices and readily available market data. These values are based upon, among other things, futures prices, volatility, time to maturity and credit risk. 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.

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Our results of operations each period can be impacted by our ability to estimate the level of correlation between future changes in the fair value of the hedge instruments and the transactions being hedged, both at the inception and on an ongoing basis. This correlation is complicated since energy commodity prices, the primary risk we hedge, have quality and location differences that can be difficult to hedge effectively. The factors underlying our estimates of fair value and our assessment of correlation of our hedging derivatives are impacted by actual results and changes in conditions that affect these factors, many of which are beyond our control. If our derivative contracts would not qualify for cash flow hedge treatment, then our consolidated statements of income could include large non-cash fluctuations, particularly in volatile pricing environments, as our contracts are marked to their period end market values.

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 Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. 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 gas prices). In July 2006, the FASB issued Interpretation No. 48, Accounting for Uncertainty in Income Taxes — An Interpretation of FASB Statement No. 109 ("FIN 48"), which requires income tax positions to meet a more-likely-than-not recognition threshold to be recognized in the financial statements. Under FIN 48, 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 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 estimated 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 using the purchase method, which is the only method permitted under SFAS No. 141, Business Combinations, and involves the use of significant judgment.

Under the purchase method of accounting, a business combination is accounted for at a purchase price based upon the fair value of the consideration given. The assets and liabilities acquired are measured at their fair values, and the purchase price is allocated to the assets and liabilities based upon these fair values. The excess of the cost of an acquired entity, if any, over the net amounts assigned to assets acquired and liabilities assumed is recognized as goodwill. The excess of the fair value of assets acquired and liabilities assumed over the cost of an acquired entity, if any, is allocated as a pro rata reduction of the amounts that otherwise would have been assigned to certain acquired assets.

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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 or companies with oil and gas interests. 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 recognized from any of our business combinations.

Effects of Inflation and Pricing

We experienced increased costs during 2007, 2006 and 2005 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 gas increase, so do all associated costs. Conversely, in a period of declining prices, associated cost declines are likely to lag and may not adjust downward in proportion. Material changes in prices also impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans 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, continued high prices for oil and 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.

These risks and uncertainties include, but are not limited to: declines in oil or gas prices; our level of success in exploitation, exploration, development and production activities; adverse weather conditions that may negatively impact development or production activities; the timing of our exploration and development expenditures, including our ability to obtain drilling rigs and CO_2; our ability to obtain external capital to finance acquisitions; our ability to identify and complete acquisitions and to successfully integrate acquired businesses, including our ability to realize cost savings from completed acquisitions; unforeseen underperformance of or liabilities associated with acquired properties; our ability to successfully complete our planned and potential asset dispositions; inaccuracies of our reserve estimates or our assumptions underlying them; failure of our properties to yield oil or gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and gas operations; our inability to access oil and gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and gas operations; risks related to our level of indebtedness and periodic redeterminations of our borrowing base under our credit agreement; our ability to replace our oil and 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 report.

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Item 7A. Quantitative and Qualitative Disclosure 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 2007 production, our income before income taxes for 2007 would have moved up or down $9.6 million for each $1.00 change in oil prices and $3.1 million for every $0.10 change in gas prices.

We periodically enter into derivative contracts to manage our exposure to oil and gas price volatility. Our derivative contracts have traditionally been costless collars, although we evaluate other forms of derivative instruments as well. Our derivative contracts have historically qualified for cash flow hedge accounting, whereby accounting rules allow the aggregate change in fair market value to be recorded as accumulated other comprehensive income (loss). 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 January 1, 2008 are summarized below:

Commodity	Period	Monthly Volume (MMbtu)/(Bbl)	NYMEX Floor/Ceiling
Crude Oil	01/2008 to 03/2008	110,000	$49.00/$70.65
Crude Oil	01/2008 to 03/2008	120,000	$60.00/$73.90
Crude Oil	01/2008 to 03/2008	100,000	$65.00/$80.30
Crude Oil	04/2008 to 06/2008	110,000	$48.00/$71.60
Crude Oil	04/2008 to 06/2008	120,000	$60.00/$74.65
Crude Oil	04/2008 to 06/2008	100,000	$65.00/$80.50
Crude Oil	07/2008 to 09/2008	110,000	$48.00/$70.85
Crude Oil	07/2008 to 09/2008	120,000	$60.00/$75.60
Crude Oil	07/2008 to 09/2008	100,000	$65.00/$81.00
Crude Oil	10/2008 to 12/2008	110,000	$48.00/$70.20
Crude Oil	10/2008 to 12/2008	120,000	$60.00/$75.85
Crude Oil	10/2008 to 12/2008	100,000	$65.00/$81.20

The crude oil collars shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. While these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the 2008 crude oil contracts listed above, a hypothetical $1.00 change in the NYMEX price would cause a change in the gain (loss) on hedging activities in 2008 of $4.0 million.

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In a 1997 non-operated property acquisition, we became subject to the operator's fixed price gas sales contract with end users for a portion of the natural gas we produce in Michigan. This contract has built-in pricing escalators of 4% per year. Our estimated future production volumes to be sold under the fixed pricing terms of this contract as of January 1, 2008 are summarized below:

Commodity	Period Remaining	Monthly Volume (MMbtu)	2008 Price Per MMbtu
Natural Gas	01/2008 to 05/2011	26,000	$ 4.94
Natural Gas	01/2008 to 09/2012	67,000	$ 4.38

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 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, 2007, our outstanding principal balance under our credit agreement was $250.0 million and the weighted average interest rate on the outstanding principal balance was fixed at 6.1% through January 2008. At December 31, 2007, the carrying amount approximated fair market value. Assuming a constant debt level of $250.0 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 $2.3 million.

Interest Rate Swap

In August 2004, we entered into an interest rate swap contract to hedge the fair value of $75.0 million of our 7.25% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that we receive the fixed rate of 7.25% and pay the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus our margin of 2.345% is less than 7.25%, we receive a payment from the counterparty equal to the difference in rate times $75.0 million for the six month period. When LIBOR plus our margin of 2.345% is greater than 7.25%, we pay the counterparty an amount equal to the difference in rate times $75.0 million for the six month period. The LIBOR rate as of the November 1, 2007 swap reset date was 4.82%. As of December 31, 2007, we have recorded a long term asset of $0.8 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding increase in the carrying value of the Senior Subordinated Notes.

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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, 2007 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, 2007, 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, 2007 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:

We have audited the internal control over financial reporting of Whiting Petroleum Corporation and its subsidiaries (the “Company”) as of December 31, 2007 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, 2007, 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, 2007 of the Company and our report dated February 28, 2008, expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 28, 2008

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Whiting Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and subsidiaries (the "Company") as of December 31, 2007 and 2006, 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, 2007. 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, 2007 and 2006, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2007, 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, present fairly, in all material respects, the information set forth therein.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2007, based on the criteria established in Internal Control—Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 28, 2008 expressed an unqualified opinion on the Company's internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 28, 2008

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands)

	December 31, 2007	December 31, 2006
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 14,778	$ 10,372
Accounts receivable trade, net	110,437	97,831
Deferred income taxes	27,720	3,025
Prepaid expenses and other	9,232	10,484
Total current assets	162,167	121,712
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	3,313,777	2,828,282
Unproved properties	55,084	55,297
Other property and equipment	37,778	44,902
Total property and equipment	3,406,639	2,928,481
Less accumulated depreciation, depletion and amortization	(646,943)	(495,820)
Total property and equipment, net	2,759,696	2,432,661
DEBT ISSUANCE COSTS	15,016	19,352
OTHER LONG-TERM ASSETS	15,132	11,678
TOTAL	$ 2,952,011	$ 2,585,403

See notes to consolidated financial statements. (Continued)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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

LIABILITIES AND STOCKHOLDERS' EQUITY	December 31, 2007	December 31, 2006
CURRENT LIABILITIES:		
Accounts payable	$ 19,280	$ 21,077
Accrued capital expenditures	59,441	28,127
Accrued liabilities	29,098	30,377
Accrued interest	11,240	9,124
Oil and gas sales payable	26,205	19,064
Accrued employee compensation and benefits	21,081	17,800
Production taxes payable	12,936	9,820
Current portion of tax sharing liability	2,587	3,565
Current portion of derivative liability	72,796	4,088
Total current liabilities	254,664	143,042
NON-CURRENT LIABILITIES:		
Long-term debt	868,248	995,396
Asset retirement obligations	35,883	36,982
Production Participation Plan liability	34,042	25,443
Tax sharing liability	23,070	23,607
Deferred income taxes	242,964	165,031
Long-term derivative liability	-	5,248
Other long-term liabilities	2,314	3,984
Total non-current liabilities	1,206,521	1,255,691
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $0.001 par value; 75,000,000 shares authorized, 42,480,497 and 36,947,681 shares issued as of December 31, 2007 and 2006, respectively	42	37
Additional paid-in capital	968,876	754,788
Accumulated other comprehensive loss	(46,116)	(5,902)
Retained earnings	568,024	437,747
Total stockholders' equity	1,490,826	1,186,670
TOTAL	$ 2,952,011	$ 2,585,403

See notes to consolidated financial statements. (Concluded)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME
(In thousands, except per share data)

	Year Ended December 31, 2007	2006	2005
REVENUES AND OTHER INCOME:			
Oil and natural gas sales	$ 809,017	$ 773,120	$ 573,246
Loss on oil and natural gas hedging activities	(21,189)	(7,501)	(33,377)
Gain on sale of properties	29,682	12,092	-
Interest income and other	1,208	1,116	579
Total revenues and other income	818,718	778,827	540,448
COSTS AND EXPENSES:			
Lease operating	208,866	183,642	111,560
Production taxes	52,407	47,095	36,092
Depreciation, depletion and amortization	192,811	162,831	97,639
Exploration and impairment	37,323	34,534	16,699
General and administrative	39,046	37,808	30,607
Change in Production Participation Plan liability	8,599	6,156	9,708
Interest expense	72,504	73,489	42,045
Total costs and expenses	611,556	545,555	344,350
INCOME BEFORE INCOME TAXES	207,162	233,272	196,098
INCOME TAX EXPENSE:			
Current	550	12,346	8,514
Deferred	76,012	64,562	65,662
Total income tax expense	76,562	76,908	74,176
NET INCOME	$ 130,600	$ 156,364	$ 121,922
NET INCOME PER COMMON SHARE, BASIC	$ 3.31	$ 4.26	$ 3.89
NET INCOME PER COMMON SHARE, DILUTED	$ 3.29	$ 4.25	$ 3.88
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	39,483	36,736	31,356
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	39,645	36,826	31,449

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2007	2006	2005
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 130,600	$ 156,364	$ 121,922
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	192,811	162,831	97,639
Deferred income taxes	76,012	64,562	65,662
Amortization of debt issuance costs and debt discount	5,022	5,208	4,076
Accretion of tax sharing liability	1,505	2,016	2,725
Stock-based compensation	5,057	3,969	2,861
Gain on sale of properties	(29,682)	(12,092)	-
Undeveloped leasehold and oil and gas property impairments	9,979	4,455	2,034
Change in Production Participation Plan liability	8,599	6,156	9,708
Other non-current	(5,086)	2,653	373
Changes in current assets and liabilities:			
Accounts receivable trade	(12,606)	3,235	(35,012)
Prepaid expenses and other	1,404	(2,268)	(302)
Accounts payable and accrued liabilities	(3,833)	20,412	20,077
Accrued interest	2,116	(2,770)	9,844
Other liabilities	12,134	(3,522)	28,586
Net cash provided by operating activities	394,032	411,209	330,193
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash acquisition capital expenditures	(21,568)	(87,562)	(900,332)
Drilling and development capital expenditures	(497,988)	(464,407)	(196,163)
Proceeds from sale of oil and gas properties	52,585	24,390	-
Acquisition of partnership interests, net of cash acquired of $26	-	-	(30,433)
Net cash used in investing activities	(466,971)	(527,579)	(1,126,928)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Issuance of common stock	210,394	-	277,117
Issuance of 7.25% Senior Subordinated Notes due 2013	-	-	216,715
Issuance of 7% Senior Subordinated Notes due 2014	-	-	250,000
Long-term borrowings under credit agreement	384,400	325,000	395,000
Repayments of long-term borrowings under credit agreement	(514,400)	(205,000)	(310,000)
Repayments to Alliant Energy Corporation	(3,019)	(3,675)	(8,242)
Debt issuance costs	(75)	(253)	(15,370)
Tax effect from restricted stock vesting	45	288	237
Net cash provided by financing activities	77,345	116,360	805,457
NET CHANGE IN CASH AND CASH EQUIVALENTS	4,406	(10)	8,722
CASH AND CASH EQUIVALENTS:			
Beginning of period	10,372	10,382	1,660
End of period	$ 14,778	$ 10,372	$ 10,382

See notes to consolidated financial statements. (Continued)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31,		
	2007	2006	2005
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid for income taxes	$ 1,446	$ 12,063	$ 10,620
Cash paid for interest	$ 63,861	$ 69,034	$ 26,113
NONCASH INVESTING ACTIVITIES:			
Accrued capital expenditures during the year	$ 59,441	$ 28,127	$ 37,544
NONCASH FINANCING ACTIVITIES:			
Issuance of common stock – North Ward Estes acquisition	$ -	$ -	$ 17,175

See notes to consolidated financial statements. (Concluded)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY AND COMPREHENSIVE INCOME
(In thousands)

	Common Stock Shares	Common Stock Amount	Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Retained Earnings	Total Stockholders' Equity	Comprehensive Income
BALANCES-January 1, 2005	29,718	$ 30	$ 455,635	$ (1,025)	$ (1,715)	$ 159,461	$ 612,386	
Net income	-	-	-	-	-	121,922	121,922	$ 121,922
Change in derivative fair values, net of taxes of $34,004	-	-	-	(54,089)	-	-	(54,089)	(54,089)
Realized loss on settled derivative contracts, net of taxes of $12,884	-	-	-	20,494	-	-	20,494	20,494
Restricted stock issued	85	-	3,407	-	(3,407)	-	-	-
Restricted stock forfeited	(9)	-	(230)	-	230	-	-	-
Restricted stock used for tax withholdings	(6)	-	(241)	-	-	-	(241)	-
Tax effect from restricted stock vesting	-	-	237	-	-	-	237	-
Issuance of stock – secondary offering	6,612	7	277,110	-	-	-	277,117	-
Issuance of stock – North Ward Estes acquisition	442	-	17,175	-	-	-	17,175	-
Amortization of deferred compensation	-	-	-	-	2,861	-	2,861	-
BALANCES-December 31, 2005	36,842	37	753,093	(34,620)	(2,031)	281,383	997,862	$ 88,327
Net income	-	-	-	-	-	156,364	156,364	156,364
Change in derivative fair values, net of taxes of $15,409	-	-	-	24,140	-	-	24,140	24,140
Realized loss on settled derivative contracts, net of taxes of $2,923	-	-	-	4,578	-	-	4,578	4,578
Restricted stock issued	126	-	-	-	-	-	-	-
Restricted stock forfeited	(10)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(10)	-	(440)	-	-	-	(440)	-
Tax effect from restricted stock vesting	-	-	288	-	-	-	288	-

Adoption of SFAS 123R	-	-	(2,122)	-	2,031	-	(91)	-
Stock-based compensation	-	-	3,969	-	-	-	3,969	-
BALANCES-December 31, 2006	36,948	37	754,788	(5,902)	-	437,747	1,186,670	$ 185,082
Adoption of FIN 48	-	-	-	-	-	(323)	(323)	-
Net income	-	-	-	-	-	130,600	130,600	130,600
Change in derivative fair values, net of taxes of $31,012	-	-	-	(53,637)	-	-	(53,637)	(53,637)
Realized loss on settled derivative contracts, net of taxes of $7,766	-	-	-	13,423	-	-	13,423	13,423
Issuance of stock, secondary offering	5,425	5	210,389	-	-	-	210,394	-
Restricted stock issued	150	-	-	-	-	-	-	-
Restricted stock forfeited	(12)	-	-	-	-	-	-	-
Restricted stock used for tax withholdings	(31)	-	(1,403)	-	-	-	(1,403)	-
Tax effect from restricted stock vesting	-	-	45	-	-	-	45	-
Stock-based compensation	-	-	5,057	-	-	-	5,057	-
BALANCES-December 31, 2007	42,480	$ 42	$ 968,876	$ (46,116)	$ -	$ 568,024	$ 1,490,826	$ 90,386

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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, Whiting Oil and Gas Corporation, Equity Oil Company and Whiting Programs, Inc.

Basis of Presentation of Consolidated Financial Statements—The consolidated financial statements include the accounts of Whiting Petroleum Corporation and its consolidated subsidiaries, all of which are wholly-owned, together with its pro rata share of the assets, liabilities, revenue and expenses of limited partnerships in which Whiting was the sole general partner. In June 2005, Whiting increased its ownership interest to 100% in limited partnerships where it was the sole general partner and subsequently liquidated them. 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 earning and losses. All intercompany balances and transactions have been eliminated in 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 and disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. Items subject to such estimates and assumptions include (1) oil and 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.

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The Company routinely assesses the recoverability of all material trade and other receivables to determine their collectibility. At December 31, 2007 and 2006, the Company had an allowance for doubtful accounts of $0.3 million and $0.6 million, respectively.

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

Oil and Gas Properties

Proved. The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and development costs, including the cost of CO2 purchased for injection, 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 exploration and development projects that require greater than six months to be readied for their intended use. During 2007 and 2006, the Company capitalized $3.7 million and $0.6 million, respectively, of interest. During 2005, capitalized interest costs were insignificant.

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. Unamortized lease acquisition costs related to successful exploratory drilling are reclassified to proved properties and depleted on a unit-of-production basis. As unproved reserves are developed and proven, the associated costs are likewise 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 proved and unproved reserves, those seismic costs are proportionately allocated between development costs and exploration expense.

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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.

Other Property and Equipment. Other property and equipment, consisting mainly of an oil pipeline, furniture and fixtures, leasehold improvements, and automobiles, are stated at cost and depreciated using the straight-line method over their estimated useful lives, which range from 4 to 33 years. Also included in other property and equipment are material and supplies inventories which are not depreciated.

Debt Issuance Costs—Debt issuance costs related to 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.

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 the 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 and also enters into derivatives, interest rate swaps, to manage its exposure to interest rate risk. All derivative instruments, other than those that meet the normal purchase and sales exceptions, 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. Cash flows from derivatives used to manage commodity price risk and interest rate 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.

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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 earnings 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 net income. 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 net income.

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 net income 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 the hedge is no longer highly effective, hedge accounting is prospectively discontinued.

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 collectibility 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, 2007 and 2006, the Company was in a net (over) under produced imbalance position of (102,000) Mcf and (273,000) Mcf, respectively.

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.

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Income Taxes—Income taxes are provided 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. Effective January 1, 2007, the Company adopted Financial Accounting Standards Board ("FASB") Interpretation No. 48, Accounting for Uncertainty in Income Taxes – An Interpretation of FASB Statement No. 109 ("FIN 48"). In accordance with this pronouncement, 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.

Earnings Per Share—Basic net income per common share is calculated by dividing net income by the weighted average number of common shares outstanding during each year. Diluted net income per common share is calculated by dividing net income by the weighted average number of common shares outstanding and other dilutive securities. The only securities considered dilutive are the Company's unvested restricted stock awards.

Industry Segment and Geographic Information—The Company has evaluated how it is organized and managed and 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 interest rate swap and the related hedged portion of its Senior Subordinated Notes are recorded at fair value, as are derivative financial instruments, which are also reported on the balance sheet at fair market value.

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, including the use of master netting agreements, where appropriate. During 2007, sales to Valero Energy Corporation and Plains Marketing LP accounted for 14% and 13%, respectively, of the Company's total oil and gas production revenue. During 2006, sales to Plains Marketing LP and Valero Energy Corporation accounted for 16% and 12%, respectively, of the Company's total oil and gas production revenue. During 2005, sales to Teppco Crude Oil LLC accounted for 10% of the Company's total oil and gas production revenue.

Reclassifications—Certain reclassifications have been made to prior years' reported amounts in order to conform to the current year presentation. Such reclassifications had no impact on net income, stockholders' equity or cash flows previously reported.

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Change in Accounting Principle—In June 2006, the FASB issued FIN 48, and this interpretation creates a single model to address accounting for uncertainty in tax positions. Specifically, the pronouncement prescribes a recognition threshold and a measurement attribute for the financial statement recognition and measurement of a tax position taken or expected to be taken in a tax return. The interpretation also provides guidance on derecognition, classification, interest and penalties, accounting in interim periods, disclosure and transition of certain tax positions.

The Company adopted the provisions of FIN 48 on January 1, 2007. As a result of the implementation of FIN 48, the Company recognized a $0.3 million increase in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings and a corresponding increase in other long-term liabilities.

New Accounting Pronouncements—In September 2006, the FASB issued Statement No. 157, Fair Value Measurements ("SFAS 157"). The adoption of SFAS 157 is not expected to have a material impact on our consolidated financial position, cash flows or results of operations. However, additional disclosures may be required about the information used to develop the measurements. SFAS 157 establishes a single authoritative definition of fair value, sets out a framework for measuring fair value and requires additional disclosures about fair value measurements. This Standard requires companies to disclose the fair value of their financial instruments according to a fair value hierarchy. SFAS 157 does not require any new fair value measurements, but will remove inconsistencies in fair value measurements between various accounting pronouncements. SFAS 157 is effective for financial statements issued for fiscal years beginning after November 15, 2007 and interim periods within those fiscal years.

In February 2007, the FASB issued Statement No. 159, The Fair Value Option for Financial Assets and Financial Liabilities – Including an amendment of FASB Statement No. 115 ("SFAS 159"). SFAS 159 expands the use of fair value accounting but does not affect existing standards which require assets or liabilities to be carried at fair value. Under SFAS 159, a company may elect to use fair value to measure many financial instruments and certain other assets and liabilities at fair value. Whiting decided not to elect fair value accounting for any of our eligible items. The adoption of SFAS 159 therefore will have no impact on our consolidated financial position, cash flows or results of operations. If the use of fair value is elected (the fair value option), any upfront costs and fees related to the item must be recognized in earnings and cannot be deferred, e.g., debt issue costs. The fair value election is irrevocable and generally made on an instrument-by-instrument basis, even if a company has similar instruments that it elects not to measure based on fair value. At the adoption date, unrealized gains and losses on existing items for which fair value has been elected are reported as a cumulative adjustment to beginning retained earnings. Subsequent to the adoption of SFAS 159, changes in fair value are recognized in earnings. SFAS 159 is effective for fiscal years beginning after November 15, 2007.

In December 2007, the FASB issued Statement No. 141R, Business Combinations ("SFAS 141R"). SFAS 141R establishes principles and requirements for how the acquirer of a business recognizes and measures in its financial statements the identifiable assets acquired, the liabilities assumed, and any noncontrolling interest in the acquiree. The statement also provides guidance for recognizing and measuring the goodwill acquired in the business combination and determines what information to disclose to enable users of the financial statement to evaluate the nature and financial effects of the business combination. SFAS 141R is effective for financial statements issued for fiscal years beginning after December 15, 2008. Accordingly, any business combinations the Company engages in will be recorded and disclosed following existing GAAP until January 1, 2009. The Company expects SFAS No. 141R will have an impact on our consolidated financial statements when effective, but the nature and magnitude of the specific effects will depend upon the nature, terms and size of the acquisitions we consummate after the effective date.

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2. ACQUISITIONS AND DIVESTITURES

2007 Acquisitions

There were no significant acquisitions during the year ended December 31, 2007.

2007 Divestitures

On July 17, 2007, the Company sold its approximate 50% non-operated working interest in several gas fields located in the LaSalle and Webb Counties of Texas for total cash proceeds of $40.1 million, resulting in a pre-tax gain on sale of $29.7 million. The divested properties had estimated proved reserves of 2.3 MMBOE as of December 31, 2006, adjusted to the July 1, 2007 divestiture effective date, thereby yielding a sale price of $17.77 per BOE. The June 2007 average daily net production from these fields was 0.8 MBOE/d.

During 2007, the Company sold its interests in several additional non-core properties for an aggregate amount of $12.5 million in cash for total estimated proved reserves of 0.6 MMBOE as of the divestitures' effective dates. The divested properties are located in Colorado, Louisiana, Michigan, Montana, New Mexico, North Dakota, Oklahoma, Texas and Wyoming. The average daily net production from the divested property interests was 0.3 MBOE/d as of the dates of disposition.

2006 Acquisitions

Utah Hingeline. On August 29, 2006, Whiting acquired a 15% working interest in approximately 170,000 acres of unproved properties in the central Utah Hingeline play for $25.0 million. No producing properties or proved reserves were associated with this acquisition. As part of this transaction, the operator agreed to pay 100% of Whiting's drilling and completion costs for the first three wells in the project. The first of these three wells was drilled in the fourth quarter of 2006, but did not find commercial quantities of hydrocarbons. The second well was drilled in the fourth quarter of 2007, but it has been cased and temporarily abandoned pending resumed operations after lease stipulations allow operations to continue in the third quarter of 2008. The third well is planned to be drilled before the end of 2008.

Michigan Properties. On August 15, 2006, Whiting acquired 65 producing properties, a gathering line, gas processing plant and 30,437 net acres of leasehold held by production in Michigan. The purchase price was $26.0 million for estimated proved reserves of 1.4 MMBOE as of the acquisition effective date of May 1, 2006, resulting in a cost of $18.55 per BOE of estimated proved reserves. Proved developed reserve quantities represented 99% of the total proved reserves acquired. The average daily production from the properties was 0.6 MBOE/d as of the acquisition effective date. The Company operates 85% of the acquired properties.

The Company funded its 2006 acquisitions with cash on hand as well as through borrowings under its credit agreement.

2006 Divestitures

During 2006, the Company sold its interests in several non-core properties for an aggregate amount of $24.4 million in cash, which consisted of total estimated proved reserves of 1.4 MMBOE as of the divestitures' effective dates. The divested properties included interests in the Cessford field in Alberta, Canada; Permian Basin of West Texas and New Mexico; and the Ashley Valley field in Uintah County, Utah. The average net production from the divested property interests was 0.4 MBOE/d as of the dates of disposition, and the Company recognized a pre-tax gain of $12.1 million in the fourth quarter of 2006 on the sale of these properties.

2005 Acquisitions

North Ward Estes and Ancillary Properties. On October 4, 2005, the Company acquired the operated interest in the North Ward Estes field in Ward and Winkler counties, Texas, and certain smaller fields located in the Permian Basin. The purchase price was $459.2 million, consisting of $442.0 million in cash and 441,500 shares of the Company's common stock, for estimated proved reserves of 82.1 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of $5.58 per BOE of estimated proved reserves. Proved developed reserve quantities represented 36% of the total proved reserves acquired. The average daily production from the properties was 4.6 MBOE/d as of the acquisition effective date. The Company funded the cash portion of the purchase price with the net proceeds from the Company's public offering of common stock and private placement of 7% Senior Subordinated Notes due 2014.

Postle Field. On August 4, 2005, the Company acquired the operated interest in producing oil and gas fields located in the Oklahoma Panhandle. The purchase price was $343.0 million for estimated proved reserves of 40.3 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of $8.52 per BOE of estimated proved reserves. Proved developed reserve quantities represented 57% of the total proved reserves acquired. The average daily production from the properties was 4.2 MBOE/d as of the acquisition effective date. The Company funded the acquisition through borrowings under its credit agreement.

Limited Partnership Interests. On June 23, 2005, the Company acquired all of the limited partnership interests in three institutional partnerships managed by its wholly-owned subsidiary, Whiting Programs, Inc. The partnership properties are located in Louisiana, Texas, Arkansas, Oklahoma and Wyoming. The purchase price was $30.5 million for estimated proved reserves of 2.9 MMBOE as of the acquisition effective date of January 1, 2005, resulting in a cost of $10.52 per BOE of estimated proved reserves. Proved developed reserve quantities represented 99% of the total proved reserves acquired. The average daily production from the properties was 0.7 MBOE/d as of the acquisition effective date. The Company funded the acquisition with cash on hand.

Green River Basin. On March 31, 2005, the Company acquired operated interests in five producing natural gas fields in the Green River Basin of Wyoming. The purchase price was $65.0 million for estimated proved reserves of 8.4 MMBOE as of the acquisition effective date of March 1, 2005, resulting in a cost of $7.74 per BOE of estimated proved reserves. Proved developed reserve quantities represented 68% of the total proved reserves acquired. The average daily production from the properties was 1.1 MBOE/d as of the acquisition effective date. The Company funded the acquisition through borrowings under its credit agreement and with cash on hand.

As these acquisitions were recorded using the purchase method of accounting, the results of operations from the acquisitions are included with the Company's results from the respective acquisition dates noted above. The table below summarizes the allocation of the purchase price for each 2005 purchase transaction based on the acquisition date fair values of the assets acquired and the liabilities assumed (in thousands).

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	Postle Field	N. Ward Estes and Ancillary	All Other Acquisitions
Purchase Price:			
Cash paid, net of cash acquired	$ 343,000	$ 442,000	$ 95,433
Common stock issued	-	17,175	-
Total	$ 343,000	$ 459,175	$ 95,433
Allocation of Purchase Price:			
Working capital	$ -	$ -	$ 2,096
Oil and gas properties	343,513	463,340	95,832
Other long-term assets	243	-	-
Other non-current liabilities	(756)	(4,165)	(2,495)
Total	$ 343,000	$ 459,175	$ 95,433

Acquisition Pro Forma

Pro forma effects of 2007 and 2006 acquisitions were insignificant to the Company's results of operations. The following table reflects the pro forma results of operations for the year ended December 31, 2005 as though the above 2005 acquisitions had occurred on January 1, 2005. The pro forma information includes numerous assumptions and is not necessarily indicative of future results of operations.

	Year Ended December 31, 2005	
	As Reported	Pro Forma
	(In thousands, except per common share data)	
Revenues and other income	$ 540,448	$ 652,634
Net income	121,922	155,462
Net income per common share, basic	3.89	4.05
Net income per common share, diluted	3.88	4.04

3. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2007 and 2006 (in thousands):

	December 31,	
	2007	2006
Credit agreement	$ 250,000	$ 380,000
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $537 and $687, respectively	150,214	147,820
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,966 and $2,424, respectively	218,034	217,576
7% Senior Subordinated Notes due 2014	250,000	250,000
Total debt	$ 868,248	$ 995,396

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Credit Agreement—The Company's wholly-owned subsidiary, Whiting Oil and Gas Corporation ("Whiting Oil and Gas") has a $1.2 billion credit agreement with a syndicate of banks that, as of December 31, 2007, had a borrowing base of $900.0 million. 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. As of December 31, 2007, outstanding borrowings under the credit agreement totaled $250.0 million.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. Whiting Oil and Gas may, throughout the five-year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect at any given time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas or other designated subsidiaries of the Company in an aggregate amount not to exceed $50.0 million. As of December 31, 2007, letters of credit totaling $0.2 million were outstanding under the credit agreement.

Interest accrues, at Whiting Oil and Gas' option at either (1) the base rate plus a margin, where the base rate is defined as the higher of the prime rate or the federal funds rate plus 0.5% and the margin varies from 0% to 0.5% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin, where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. The Company has consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.25% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage, and are included as a component of interest expense. At December 31, 2007, the weighted average interest rate on the outstanding principal balance under the credit agreement was 6.1%.

The credit agreement contains restrictive covenants that may limit the Company's ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, enter into hedging contracts, change material agreements, incur liens and engage in certain other transactions without the prior consent of the lenders and requires the Company to maintain a debt to EBITDAX ratio (as defined in the credit agreement) of less than 3.5 to 1 and a working capital ratio (as defined in the credit agreement which includes an add back of the available borrowing capacity under the credit facility) of greater than 1 to 1. Except for limited exceptions, including the payment of interest on the senior notes, the credit agreement restricts the ability of Whiting Oil and Gas and Whiting Petroleum Corporation's wholly-owned subsidiary, Equity Oil Company, to make any dividends, distributions, principal payments on senior notes, or other payments to Whiting Petroleum Corporation. The restrictions apply to all of the net assets of these subsidiaries. The Company was in compliance with its covenants under the credit agreement as of December 31, 2007. The credit agreement is secured by a first lien on all of Whiting Oil and Gas' properties included in the borrowing base for the credit agreement. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas and Equity Oil Company as security for its guarantee, and Equity Oil Company has mortgaged all of its properties, that are included in the borrowing base for the credit agreement, as security for its guarantee.

Senior Subordinated Notes—In October 2005, the Company issued at par $250.0 million of 7% Senior Subordinated Notes due 2014. The estimated fair value of these notes was $246.6 million as of December 31, 2007.

In April 2005, the Company issued $220.0 million of 7.25% Senior Subordinated Notes due 2013. These notes were issued at 98.507% of par, and the associated discount of $3.3 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.5%. The estimated fair value of these notes was $215.9 million as of December 31, 2007.

In May 2004, the Company issued $150.0 million of 7.25% Senior Subordinated Notes due 2012. These notes were issued at 99.26% of par, and the associated discount of $1.1 million is being amortized to interest expense over the term of these notes, yielding an effective interest rate of 7.4%. The estimated fair value of these notes was $147.0 million as of December 31, 2007.

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 indentures governing the notes contain various restrictive covenants that are substantially identical and may limit the Company's ability to, among other things, pay cash dividends, redeem or repurchase the Company's capital stock or the Company's subordinated debt, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of the Company and its restricted subsidiaries taken as a whole, and enter into hedging contracts. These covenants may potentially limit the discretion of the Company's management in certain respects. The Company was in compliance with these covenants as of December 31, 2007. The Company's wholly-owned operating subsidiaries, Whiting Oil and Gas, Whiting Programs, Inc. and Equity Oil Company (the "Guarantors"), have fully, unconditionally, jointly and severally guaranteed the Company's obligations under the notes. The Company does not have any subsidiaries other than the Guarantors, minor or otherwise, within the meaning of Rule 3-10(h)(6) of Regulation S-X of the Securities and Exchange Commission, and Whiting Petroleum Corporation has no assets or operations independent of this debt and its investments in guarantor subsidiaries.

Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of $75.0 million of its 7.25% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness, the change in fair value of the debt is assumed to equal the change in the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist between the interest rate swap and the notes.

The interest rate swap is a fixed for floating swap in that the Company receives the fixed rate of 7.25% and pays the floating rate. The floating rate is redetermined every six months based on the LIBOR rate in effect at the contractual reset date. When LIBOR plus the Company's margin of 2.345% is less than 7.25%, the Company receives a payment from the counterparty equal to the difference in rate times $75.0 million for the six month period. When LIBOR plus the Company's margin of 2.345% is greater than 7.25%, the Company pays the counterparty an amount equal to the difference in rate times $75.0 million for the six month period. The LIBOR rate at December 31, 2007 was 4.6%. For the years ended December 31, 2007, 2006 and 2005, Whiting recognized realized gains (losses) of $(0.4) million, $(0.05) million and $1.5 million, respectively, on the interest rate swap. As of December 31, 2007, the Company has recorded a long-term asset of $0.8 million related to the interest rate swap, which has been designated as a fair value hedge, with an offsetting increase to the fair value of the 7.25% Senior Subordinated Notes due 2012.

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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 determines asset retirement obligations by calculating the present value of estimated cash flows related to plug and abandonment obligations. The current portion at December 31, 2007 and 2006 is $1.3 million and $0.6 million, respectively, and is recorded in accrued liabilities. The following table provides a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2007 and 2006 (in thousands):

	Year Ended December 31,	
	2007	2006
Beginning asset retirement obligation	$ 37,534	$ 32,246
Revisions in estimated cash flows	76	3,719
Additional liability incurred	1,490	2,260
Accretion expense	2,850	2,288
Obligations on sold properties	(2,557)	(1,432)
Liabilities settled	(2,201)	(1,547)
Ending asset retirement obligation	$ 37,192	$ 37,534

5. DERIVATIVE FINANCIAL INSTRUMENTS

Whiting enters into derivative contracts, primarily costless collars, to hedge future crude oil and natural gas production in order to mitigate the risk of market price fluctuations. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Costless collars are designed to establish floor and ceiling prices on anticipated future oil and gas production. The Company has designated these contracts as cash flow hedges designed to achieve a more predictable cash flow, as well as to reduce its exposure to price volatility. 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 instruments for speculative or trading purposes.

At December 31, 2007, accumulated other comprehensive loss consisted of $72.8 million ($46.1 million after tax) of unrealized losses, representing the mark-to-market value of the Company's open commodity contracts, designated as cash flow hedges, as of the balance sheet date. At December 31, 2006, accumulated other comprehensive loss consisted of $9.3 million ($5.9 million after tax) of unrealized losses, representing the mark-to-market value of the Company's open commodity contracts, designated as cash flow hedges, as of the balance sheet date.

For the years ended December 31, 2007, 2006 and 2005, Whiting recognized realized cash settlement losses of $21.2 million, $7.5 million and $33.4 million, respectively, on commodity derivative settlements. Based on the estimated fair value of the Company's derivative contracts at December 31, 2007, it expects to reclassify net losses of $72.8 million into earnings related to derivative contracts during the next twelve months; however, actual cash settlement gains and losses recognized may differ materially. The Company has hedged 4.0 MMbbl of crude oil volumes in 2008.

The Company has also entered into an interest rate swap designated as a fair value hedge as further explained in Long-Term Debt.

6. STOCKHOLDERS' EQUITY

Common Stock Offering—On July 3, 2007, the Company completed a public offering of its common stock under its existing shelf registration statement, selling 5,425,000 shares of common stock at a price of $40.50 per share, providing net proceeds of $210.4 million. The number of shares includes the sale of 425,000 shares pursuant to the exercise of the underwriters' overallotment option. The Company used the net proceeds to repay a portion of the debt outstanding under its credit agreement.

On October 4, 2005, the Company completed a public offering of its common stock, selling 6,612,500 shares of common stock at a price of $43.60 per share, providing net proceeds of $277.1 million. The number of shares includes the sale of 862,500 shares pursuant to the exercise of the underwriters' overallotment option. The Company used the net proceeds to pay the cash portion of the purchase price for the acquisition of the North Ward Estes properties and to repay a portion of the debt outstanding under its credit agreement, which incremental borrowings were incurred in connection with the acquisition of the Postle properties.

Equity Incentive Plan—The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive Plan ("the Plan"), pursuant to which two million shares of the Company's common stock have been reserved for issuance. No employee or officer participant may be granted options for more than 300,000 shares of common stock, stock appreciation rights with respect to more than 300,000 shares of common stock, or more than 150,000 shares of restricted stock during any calendar year.

Restricted stock awards for executive officers, directors and employees generally vest ratably over three years. In February 2007, however, restricted stock awards granted to executive officers included certain performance conditions, in addition to the standard three-year service condition, that must be met in order for the stock awards to vest. The Company believes that it is probable that such performance conditions will be achieved and has accrued compensation cost accordingly for its 2007 restricted stock grants to executives.

The following table shows a summary of the Company's nonvested restricted stock as of December 31, 2005, 2006 and 2007 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, 2005	105,197	$	21.83
Granted	84,652	$	40.26
Vested	(28,699)	$	21.73
Forfeited	(15,387)	$	23.19
Restricted stock awards nonvested, December 31, 2005	145,763	$	32.34
Granted	125,999	$	43.38
Vested	(58,409)	$	27.81
Forfeited	(10,089)	$	37.87
Restricted stock awards nonvested, December 31, 2006	203,264	$	39.33
Granted	150,815	$	45.24
Vested	(101,985)	$	36.13

Forfeited	(12,438)	$	44.28
Restricted stock awards nonvested, December 31, 2007	239,656	$	44.15

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The grant date fair value of restricted stock is determined based on the closing bid price of the Company's common stock on the grant date. 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.

As of December 31, 2007, there was $3.5 million of total unrecognized compensation cost related to unvested restricted stock granted under the Plan. That cost is expected to be recognized over a weighted average period of 1.9 years. For the years ended December 31, 2007, 2006 and 2005, the total fair value of restricted stock vested was $4.7 million, $2.6 million and $1.4 million, respectively.

Rights Agreement—On February 23, 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. 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.

7. EMPLOYEE BENEFIT PLANS

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. 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, 2007, 2006 and 2005 amounted to $15.8 million, $13.2 million and $10.2 million, respectively, charged to general and administrative expense and $2.8 million, $2.5 million and $1.9 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, (1) employees who terminate their employment with the Company are entitled to receive their vested allocation of future Plan year payments on an annual basis; (2) employees will become fully vested at age 62, regardless of when their interests would otherwise vest; and (3) any forfeitures for Plan years after 2003 inure to the benefit of the Company.

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The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At December 31, 2007, the Company used five-year average historical NYMEX prices of $54.82 for crude oil and $6.68 for natural gas to estimate this liability. If the Company were to terminate the Plan or upon a change in control (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 prices at December 31, 2007, 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 $125.2 million. This amount includes $20.8 million attributable to proved undeveloped oil and gas properties and $18.6 million relating to the short-term portion of the Plan liability, which has been accrued as a current payable to be paid in February 2008. The ultimate sharing contribution for proved undeveloped oil and gas properties will be awarded in the year of Plan termination or change of control. However, the Company has no intention to terminate the Plan.

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

	Year Ended December 31,	
	2007	2006
Beginning Production Participation Plan liability	$ 25,443	$ 19,287
Change in liability for accretion, vesting and change in estimates	27,225	21,849
Reduction in liability for cash payments accrued and recognized as compensation expense	(18,626)	(15,693)
Ending Production Participation Plan liability	$ 34,042	$ 25,443

The Company records the expense associated with changes in the present value of estimated non-current 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 table below presents the estimated allocation of the change in the non-current portion of the liability if the Company did allocate the adjustment to these specific line items (in thousands).

	Year Ended December 31,		
	2007	2006	2005
General and administrative expense	$ 7,293	$ 5,196	$ 8,186
Exploration expense	1,306	960	1,522
Total	$ 8,599	$ 6,156	$ 9,708

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 2007, 2006 and 2005 were $2.4 million, $2.1 million and $1.2 million, respectively. Employees vest in employer contributions at 20% per year of completed service.

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8. INCOME TAXES

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

	Year Ended December 31,		
	2007	2006	2005
Current income tax expense:			
Federal	$ 32	$ 11,576	$ 5,076
State	518	770	3,438
Total current income tax expense	550	12,346	8,514
Deferred income tax expense:			
Federal	72,937	65,402	59,538
State	3,075	(840)	6,124
Total deferred income tax expense	76,012	64,562	65,662
Total	$ 76,562	$ 76,908	$ 74,176

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,		
	2007	2006	2005
U.S. statutory income tax expense	$ 72,506	$ 81,645	$ 68,634
State income taxes, net of federal benefit	4,176	907	7,028
Tax credits	330	(4,206)	(929)
Statutory depletion	(405)	(1,245)	(434)
Enacted changes in state tax laws	(599)	(1,295)	-
Change in valuation allowance	67	1,163	-
Permanent items	570	(187)	(123)
Other	(83)	126	-
Total	$ 76,562	$ 76,908	$ 74,176

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The principal components of the Company's deferred income tax assets and liabilities at December 31, 2007 and 2006 were as follows (in thousands):

	Year Ended December 31, 2007	2006
Deferred income tax assets:		
Net operating loss carryforward	$ 20,952	$ -
Derivative instruments	26,680	3,433
Production Participation Plan liability	12,581	9,357
Tax sharing liability	10,598	9,993
Asset retirement obligations	11,806	11,673
Restricted stock compensation	2,274	1,849
Enhanced oil recovery credit carryforwards	7,946	6,894
Alternative minimum tax credit carryforwards	9,653	9,900
State deductibles	2,135	-
Foreign tax credit carryforwards	1,230	1,560
Other	110	-
Total deferred income tax assets	105,965	54,659
Less valuation allowances	(1,230)	(1,163)
Net deferred income tax assets	104,735	53,496
Deferred income tax liabilities:		
Oil and gas properties	319,979	215,488
Other	-	14
Total deferred income tax liabilities	319,979	215,502
Total net deferred income tax liabilities	$ 215,244	$ 162,006

At December 31, 2007, the Company had federal and state net operating loss carryforwards of $21.0 million. If unutilized, the federal net operating loss will expire in 2027 and the state net operating loss will expire between 2012 and 2027.

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, 2007, 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. Due to recent high oil prices, the EOR credit was phased-out for 2007 and 2006.

The Company is subject to the alternative minimum tax ("AMT") principally due to accelerated tax depreciation. As of December 31, 2007, the Company had AMT credits totaling $9.7 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, 2007, the Company's foreign tax credit carryforwards totaled $1.2 million, which will expire between 2024 and 2026. As of December 31, 2007, 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 recent divestitures 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,			
	2007		2006	
Assets:				
Current deferred income taxes	$	27,720	$	3,025
Liabilities:				
Non-current deferred income taxes		242,964		165,031
Net deferred income tax liabilities	$	215,244	$	162,006

On January 1, 2007, the Company adopted the provisions of FIN 48. As a result of the implementation of FIN 48, the Company recognized a $0.3 million increase in the liability for unrecognized tax benefits, which was accounted for as a reduction to the January 1, 2007 balance of retained earnings and a corresponding increase in other long-term liabilities. As of the adoption date after recognizing the increase noted above, the Company's liability for unrecognized tax benefits totaled $0.4 million. The following table summarizes the activity during the year related to the liability for unrecognized tax benefits (in thousands):

	Year Ended December 31, 2007	
Beginning balance at January 1	$	396
Increases related to amended returns		96
Decreases associated with accounting method change		(322)
Ending balance at December 31	$	170

Included in the unrecognized tax benefit balance at December 31, 2007, are $0.2 million of tax positions, the allowance of which would positively affect the annual effective income tax rate. For the year ended December 31, 2007, 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 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 2004 through 2007 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 2001 through 2007.

Prior to November 23, 2003, Whiting was owned 100% by Alliant Energy Corporation ("Alliant Energy"). Alliant Energy is presently under audit by the IRS for the years 1999 through 2003. Based on discussions with Alliant Energy, the Company believes that there are no issues that would require adjustment to Whiting's tax liability for the periods 1999 to 2001. Information is not yet available for the 2002 to 2003 periods.

9. RELATED PARTY TRANSACTIONS

Prior to Whiting's initial public offering in November 2003, it was a wholly-owned indirect subsidiary of 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.

Tax Sharing Liability—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 the deemed purchase price of their assets 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. The Company has estimated total payments to Alliant will approximate $34.7 million on an undiscounted basis.

During 2007, 2006 and 2005, the Company made payments of $3.0 million, $3.7 million and $5.1 million, respectively, under this agreement and recognized accretion expense of $1.5 million, $2.0 million and $2.7 million, respectively, which is included as a component of interest expense. The Company's estimated payment of $2.6 million to be made in 2008 under this agreement is reflected as a current liability at December 31, 2007.

The Tax Separation and Indemnification Agreement provides that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in 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.

Receivable from Alliant Energy—Prior to the Company's initial public offering, the Company was included in the consolidated federal income tax return of Alliant Energy and calculated its income tax expense on a separate return basis at Alliant Energy's effective tax rate, less any research or Section 29 tax credits generated by the Company. Current tax due under this calculation was paid to Alliant Energy, and current refunds were received from Alliant Energy. Section 29 tax credits were generated by Whiting in 2002, and on a stand-alone basis Whiting would have been unable to use the credits in its 2002 tax return. The Company therefore had a current receivable from Alliant Energy of $4.1 million for these credits. During 2007, Whiting received payment in full, as the credits were entirely utilized by Alliant Energy.

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

10. COMMITMENTS AND CONTINGENCIES

Non-cancelable Leases—The Company leases 87,000 square feet of administrative office space in Denver, Colorado under an operating lease arrangement through October 31, 2010 and an additional 30,100 square feet of office space in Midland, Texas through February 15, 2012. Rental expense for 2007, 2006 and 2005 amounted to $2.1 million, $1.9 million and $1.5 million, respectively. Minimum lease payments under the terms of non-cancelable operating leases as of December 31, 2007 are as follows (in thousands):

2008	$	2,003
2009		2,017
2010		1,753
2011		381
2012		71
Total	$	6,225

Purchase Contracts—The Company has two take-or-pay purchase agreements, one agreement expiring in March 2014 and one agreement 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 enhanced recovery projects in the Postle field in Texas County, Oklahoma and the North Ward Estes field in Ward County, 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 delivery was to have occurred. The CO2 volumes planned for use on the enhanced recovery projects in the Postle and North Ward Estes fields currently exceed the minimum daily volumes provided in these take-or-pay purchase agreements. Therefore, the Company expects to avoid any payments for deficiencies. As of December 31, 2007, future commitments under the purchase agreements amounted to $367.7 million through 2014.

Drilling Contracts—The Company has two drilling rigs under contract through 2008, two drilling rigs through 2009, one drilling rig through 2010, and a workover rig under contract through 2009, all of which are operating in the Rocky Mountains region. As of December 31, 2007, these agreements had total commitments of $56.4 million and early termination would require maximum penalties of $41.2 million. Other drilling rigs working for the Company are not under long-term contracts but instead 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.

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11. OIL AND GAS ACTIVITIES

The Company's oil and gas activities for 2007 were entirely within the United States. During 2006 and 2005, the Company had insignificant foreign oil and gas operations. Costs incurred in oil and gas producing activities were as follows (in thousands):

	Year Ended December 31, 2007	2006	2005
Unproved property acquisition	$ 13,598	$ 38,628	$ 16,124
Proved property acquisition	8,128	29,778	906,208
Development	506,057	408,828	215,162
Exploration	56,741	81,877	22,532
Total	$ 584,524	$ 559,111	$ 1,160,026

During 2007, 2006 and 2005, additions to oil and gas properties of $1.5 million, $2.3 million and $8.1 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, 2007	2006
Proved oil and gas properties	$ 3,313,777	$ 2,828,282
Unproved oil and gas properties	55,084	55,297
Accumulated depreciation, depletion and amortization	(637,549)	(489,550)
Oil and gas properties, net	$ 2,731,312	$ 2,394,029

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, 2007	2006	2005
Beginning balance at January 1	$ 10,194	$ 4,193	$ 2,937
Additions to capitalized exploratory well costs pending the determination of proved reserves	19,203	51,798	6,500
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(28,872)	(43,276)	(5,244)
Capitalized exploratory well costs charged to expense	-	(2,521)	-
Ending balance at December 31	$ 525	$ 10,194	$ 4,193

At December 31, 2007, the Company had no exploratory well costs capitalized for a period of greater than one year after the completion of drilling.

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

The estimates of proved reserves and related valuations were based 100% on reports prepared by the Company's independent petroleum engineers, Cawley, Gillespie & Associates, Inc. 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, 2007, 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, 2005, 2006 and 2007, are as follows:

	Oil (Mbbl)	Natural Gas (MMcf)
Balance—January 1, 2005	87,588	339,856
Extensions and discoveries	1,956	21,068
Sales of minerals in place	-	-
Purchases of minerals in place	115,737	101,082
Production	(7,032)	(30,272)
Revisions to previous estimates	950	(45,322)
Balance—December 31, 2005	199,199	386,412
Extensions and discoveries	4,125	19,362
Sales of minerals in place	(1,213)	(983)
Purchases of minerals in place	670	4,009
Production	(9,799)	(32,147)
Revisions to previous estimates	2,053	(57,780)
Balance—December 31, 2006	195,035	318,873
Extensions and discoveries	10,973	40,936
Sales of minerals in place	(1,194)	(10,382)
Purchases of minerals in place	691	-
Production	(9,579)	(30,764)
Revisions to previous estimates	392	8,079
Balance—December 31, 2007	196,318	326,742
Proved developed reserves:		
December 31, 2005	111,954	267,429
December 31, 2006	122,496	226,516
December 31, 2007	127,291	237,030

As discussed in Employee Benefit Plans, all of the Company's employees participate in the Company's Production Participation Plan. The reserve disclosures above include oil and gas reserve volumes that have been allocated to the Production Participation Plan ("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.

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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 gas reserves were prepared in accordance with the provisions of SFAS No. 69. Future cash inflows 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 gas reserves at year end, based on year-end costs and assuming 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 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 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 procedure does not necessarily result in an estimate of the fair market value or the present value of the Company's oil and gas properties.

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

	December 31,		
	2007	2006	2005
Future cash flows	$ 19,747,430	$ 12,635,239	$ 14,294,674
Future production costs	(6,022,667)	(4,248,973)	(4,484,415)
Future development costs	(1,186,826)	(1,176,778)	(909,093)
Future income tax expense	(3,952,146)	(2,064,596)	(2,773,077)
Future net cash flows	8,585,791	5,144,892	6,128,089
10% annual discount for estimated timing of cash flows	(4,574,125)	(2,752,650)	(3,245,188)
Standardized measure of discounted future net cash flows	$ 4,011,666	$ 2,392,242	$ 2,882,901

Future cash flows as shown above were reported without consideration for the effects of hedging transactions outstanding at each period end. If the effects of hedging transactions were included in the computation, then future cash flows would have decreased by $81.8 million in 2007, increased by $2.3 million in 2006, and decreased by $7.3 million in 2005.

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

	December 31,		
	2007	2006	2005
	(in thousands)		
Beginning of year	$ 2,392,242	$ 2,882,901	$ 1,312,054
Sale of oil and gas produced, net of production costs	(547,744)	(542,383)	(425,594)
Sales of minerals in place	(72,360)	(30,520)	-
Net changes in prices and production costs	2,261,006	(579,948)	628,987
Extensions, discoveries and improved recoveries	440,337	162,969	104,609
Development costs, net	(4,030)	(212,076)	(361,356)
Purchases of mineral in place	17,098	29,663	2,321,289
Revisions of previous quantity estimates	43,019	(167,956)	(115,617)
Net change in income taxes	(757,127)	561,302	(766,485)
Accretion of discount	239,224	288,290	185,014
End of year	$ 4,011,665	$ 2,392,242	$ 2,882,901

Average wellhead prices in effect at December 31, 2007, 2006 and 2005 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation were as follows:

	2007	2006	2005
Oil (per Bbl)	$ 88.62	$ 54.81	$ 55.10
Gas (per Mcf)	$ 6.31	$ 5.41	$ 7.97

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13. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited quarterly financial data for the years ended December 31, 2007 and 2006 (in thousands, except per share data):

	Three Months Ended				
	March 31, 2007	June 30, 2007	September 30, 2007	December 31, 2007	Year
Year ended December 31, 2007:					
Oil and natural gas sales	$ 159,714	$ 192,646	$ 205,594	$ 251,063	$ 809,017
Operating profit (1)	56,474	79,249	89,617	129,593	354,933
Net income	10,666	26,471	47,713	45,750	130,600
Basic net income per share	0.29	0.72	1.14	1.08	3.31
Diluted net income per share	0.29	0.72	1.13	1.08	3.29

	Three Months Ended				
	March 31, 2006	June 30, 2006	September 30, 2006	December 31, 2006	Year
Year ended December 31, 2006:					
Oil and natural gas sales	$ 189,865	$ 203,643	$ 207,751	$ 171,861	$ 773,120
Operating profit (1)	98,234	107,683	106,339	67,296	379,552
Net income	32,990	45,880	49,544	27,950	156,364
Basic net income per share	0.90	1.25	1.35	0.76	4.26
Diluted net income per share	0.90	1.25	1.35	0.76	4.25

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

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

None.

Item 9A. Controls and Procedures

Evaluation of disclosure controls and procedures. In accordance with Rule 13a-15(b) of the Securities Exchange Act of 1934 (the “Exchange Act”), our management evaluated, with the participation of our Chairman, President 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, 2007. Based upon their evaluation of these disclosures controls and procedures, the Chairman, President 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, 2007 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, 2007 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

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PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information included under the captions "Election of Directors," "Board of Directors and Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance" in our definitive Proxy Statement for Whiting Petroleum Corporation's 2008 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, President 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, 2007.

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Equity Compensation Plan Information

Plan Category	Number of securities to be issued upon exercise of outstanding options, warrants and rights	Weighted-average exercise price of outstanding options, warrants and rights	Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in the first column)
Equity compensation plans approved by security holders(1)	-	N/A	1,611,864(2)
Equity compensation plans not approved by security holders	-	N/A	-
Total	-	N/A	1,611,864(2)

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

(2) Excludes 239,656 shares of restricted common stock previously issued for which the restrictions have not lapsed.

Item 13. Certain Relationships, Related Transactions and Director Independence

The information required by this Item is included under the caption "Board of Directors and Corporate Governance – Transactions with Related Persons" and "Board of Directors and Corporate Governance – Independence of Directors" in the Proxy Statement and is 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, 2007 and 2006

c. Consolidated Statements of Income for the Years ended December 31, 2007, 2006 and 2005

d. Consolidated Statements of Cash Flows for the Years ended December 31, 2007, 2006 and 2005

e.

Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Years ended December 31, 2007, 2006 and 2005

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.

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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, 2007	December 31, 2006
ASSETS		
Current assets	$ 4,530	$ 7,263
Investment in subsidiaries	919,186	784,550
Intercompany receivable	1,256,550	1,044,820
TOTAL	$ 2,180,266	$ 1,836,633
LIABILITIES AND STOCKHOLDERS' EQUITY		
Current liabilities	$ 2,587	$ 3,565
Long-term debt	617,497	616,889
Other long-term liabilities	23,240	23,607
Stockholders' equity	1,536,942	1,192,572
TOTAL	$ 2,180,266	$ 1,836,633

CONDENSED STATEMENTS OF OPERATIONS
(In thousands)

	Year Ended December 31, 2007	2006	2005
Operating expenses:			
General and administrative	$ 4,290	$ 3,367	$ 2,861
Interest expense	2,112	2,671	3,269
Equity in earnings of subsidiaries	134,636	160,410	125,733
Income before income taxes	128,234	154,372	119,603
Income tax benefit	(2,366)	(1,992)	(2,319)
Net income	$ 130,600	$ 156,364	$ 121,922

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, 2007	2006	2005
Cash flows provided by (used in) operating activities	$ 4,633	$ (846)	$ (635)
Cash flows from investing activities	-	-	-
Cash flows from financing activities:			
Issuance of common stock	210,394	-	277,117
Issuance of Senior Subordinated Notes	-	-	466,715
Intercompany receivable	(212,053)	4,233	(735,192)
Other financing activities	(2,974)	(3,387)	(8,005)
Net cash (used in) provided by financing activities	(4,633)	846	635
Net change in cash and cash equivalents	-	-	-
Cash and cash equivalents:			
Beginning of period	-	-	-
End of period	$ -	$ -	$ -

See notes to condensed financial statements.

NOTES TO CONDENSED FINANCIAL STATEMENTS

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 2007 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, Whiting Oil and Gas Corporation's credit agreement restricts the ability of the subsidiaries to make any dividends, 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.

Reclassifications—Certain prior period balances were reclassified to conform to the current year presentation, and such reclassifications had no impact on net income or stockholders' equity previously reported.

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Schedule I

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, 2007 and 2006 (in thousands):

	December 31, 2007	December 31, 2006
Long-term debt:		
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $537 and $687, respectively	$ 149,463	$ 149,313
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $1,966 and $2,424, respectively	218,034	217,576
7% Senior Subordinated Notes due 2014	250,000	250,000
Other long-term liabilities:		
Tax sharing liability	23,070	23,607
Other	170	-
Total long-term debt and other long-term liabilities	$ 640,737	$ 640,496

Scheduled maturities of the Parent Company's long-term debt and other long-term liabilities as of December 31, 2007, were as follows (in thousands):

2008	2009	2010	2011	2012	Thereafter	Total
$ 2,587	$ 2,302	$ 2,105	$ 1,934	$ 151,765	$ 480,044	$ 640,737

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.

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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 28th day of February, 2008.

WHITING PETROLEUM CORPORATION

By /s/ James J. Volker
James J. Volker
Chairman, President 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, President, Chief Executive Officer and Director (Principal Executive Officer)	February 28, 2008
/s/ Michael J. Stevens Michael J. Stevens	Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2008
/s/ Brent P. Jensen Brent P. Jensen	Controller and Treasurer (Principal Accounting Officer)	February 28, 2008
/s/ Thomas L. Aller Thomas L. Aller	Director	February 28, 2008
/s/ D. Sherwin Artus D. Sherwin Artus	Director	February 28, 2008
/s/ Thomas P. Briggs Thomas P. Briggs	Director	February 28, 2008
/s/ William N. Hahne William N. Hahne	Director	February 28, 2008
	Director	February 28, 2008

/s/ Graydon D. Hubbard Graydon D. Hubbard		
/s/ Palmer L. Moe Palmer L. Moe	Director	February 28, 2008
/s/ Kenneth R. Whiting Kenneth R. Whiting	Director	February 28, 2008

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EXHIBIT INDEX

Exhibit Number	Exhibit Description
(3.1)	Amended and Restated Certificate of Incorporation of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation’s Registration Statement on Form S-1 (Registration No. 333-107341)].
(3.2)	Amended and Restated By-laws of Whiting Petroleum Corporation [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation’s Current Report on Form 8-K dated February 23, 2006 (File No. 001-31899)].
(3.3)	Certificate of Designations of the Board of Directors Establishing the Series and Fixing the Relative Rights and Preferences of Series A Junior Participating Preferred Stock [Incorporated by reference to Exhibit 3.1 to Whiting Petroleum Corporation’s Current Report on Form 8-K dated February 23, 2006 (File No. 001-31899)].
(4.1)	Third Amended and Restated Credit Agreement, dated as of August 31, 2005, among Whiting Oil and Gas Corporation, Whiting Petroleum Corporation, the financial institutions listed therein and JPMorgan Chase Bank, N.A., as Administrative Agent [Incorporated by reference to Exhibit 4 to Whiting Petroleum Corporation’s Current Report on Form 8-K dated August 31, 2005 (File No. 001-31899)].
(4.2)	Indenture, dated May 11, 2004, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting Programs, Inc., Equity Oil Company and J.P. Morgan Trust Company, National Association [Incorporated by reference to Exhibit 4.1 to Whiting Petroleum Corporation’s Quarterly Report on Form 10-Q for the quarter ended March 31, 2004 (File No. 001-31899)].
(4.3)	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 JPMorgan Chase Bank [Incorporated by reference to Exhibit 4.4 to Whiting Petroleum Corporation’s Registration Statement on Form S-3 (Reg. No. 333-121615)].
(4.4)	First Supplemental Indenture, dated as of April 19, 2005, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Equity Oil Company, Whiting Programs, Inc. and JP Morgan Trust Company, National Association [Incorporated by reference to Exhibit 4.2 to Whiting Petroleum Corporation’s Current Report on Form 8-K dated April 11, 2005 (File No. 001-31899)].
(4.5)	Indenture, dated October 4, 2005, by and among Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and JP Morgan Trust Company, National Association [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)].
(4.6)	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)].

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(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 [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)].
(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)*	Whiting Petroleum Corporation Production Participation Plan, as amended and restated February 4, 2008.
(10.7)	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)].
(10.8)*	Summary of Non-Employee Director Compensation for Whiting Petroleum Corporation. [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Quarterly Report on Form 10-Q for the quarter ended September 30, 2007 (File No. 001-31899)].
(10.9)*	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)].
(10.10)*	Amended and Restated Production Participation Plan Supplemental Payment Agreement, dated January 14, 2008, between Whiting Petroleum Corporation and J. Douglas Lang.
(12.1)	Statement regarding computation of ratios of earnings to fixed charges.
(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, President 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, President 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.
(99.1)	Proxy Statement for the 2008 Annual Meeting of Stockholders, to be filed within 120 days of December 31, 2007 [To be filed with the Securities and Exchange Commission under Regulation 14A within 120 days after December 31, 2007;

except to the extent specifically incorporated by reference, the Proxy Statement for the 2008 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].

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* A management contract or compensatory plan or arrangement.