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

FORM 10-K

☑ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2005

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

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

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

Common Stock, $.001 par value	New York Stock Exchange
Preferred Share Purchase Rights	New York Stock Exchange
(Title of Class)	(Name of each exchange on which registered)

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

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

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

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

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

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, or a non-accelerated filer (as defined in Rule 12b-2 of the Exchange Act). (Check one):

Large accelerated filer ☑ Accelerated filer ☐ Non-accelerated filer ☐

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

Aggregate market value of the voting common stock held by non-affiliates of the registrant at June 30, 2005: $1,077,254,303.

Number of shares of the registrant's common stock outstanding at February 15, 2006: 36,840,633 shares.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Proxy Statement for the 2005 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 operating subsidiaries. When the context requires, we refer to these entities separately.

We have included below the definitions for certain oil and natural gas 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.

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

"*frac*" The process of creating a hydraulic fracture by pumping fluid down an oil or natural gas well at high pressures for short periods of time. The hydraulic fracture allows hydrocarbons to move more freely through the rocks in which they are trapped.

"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 thousand Mcf per day.

"*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 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 and depreciation, depletion and amortization, or Federal income taxes and discounted using an annual discount rate of 10%. Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the Securities and Exchange Commission. See footnote (2) to the Proved Reserves table in "Business Overview" for more information.

"*reservoir*" A porous and permeable underground formation containing a natural accumulation of producible 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 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 and operations and all risks in connection therewith.

PART I

Item 1. Business

Overview

We are an independent oil and natural gas company engaged in exploitation, acquisition, exploration and production activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through both property acquisitions and exploitation activities. During 2005, we completed four separate acquisitions of producing properties for an aggregate purchase price of $897.7 million. The proved reserves of the acquired properties were estimated to be approximately 133.7 MMBOE as of the acquisition effective dates, representing an average cost of $6.71 per BOE of estimated proved reserves acquired. As of December 31, 2005, our estimated proved reserves totaled 263.6 MMBOE, representing an 83% increase in our proved reserves since December 31, 2004. Our estimated December 2005 average daily production was 40.7 MBOE/d, representing a 30% increase over our December 2004 average daily production and implying an average reserve life of approximately 17.7 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, 2005, and our December 2005 average daily production.

	Proved Reserves					December 2005
Core Area	Oil (MMbbl)	Natural Gas (Bcf)	Total (MMBOE)	% Oil	Pre-Tax PV10% Value(2) (In millions)	Average Daily Production (MBOE/d)
Permian Basin	105.8	84.5	119.9	88%	$ 1,621.3	12.7
Rocky Mountains(1)	40.7	105.5	58.3	70%	$ 964.4	11.9
Mid-Continent	46.6	41.9	53.6	87%	$ 859.1	5.4
Gulf Coast	4.2	83.8	18.2	23%	$ 473.2	7.8
Michigan	1.9	70.7	13.6	14%	$ 269.5	2.9
Total	**199.2**	**386.4**	**263.6**	**76%**	**$ 4,187.5**	**40.7**
Discounted Future Income Taxes	—	—	—	—	($ 1,304.6)	—
Standardized Measure of Discounted Future Net Cash Flows	—	—	—	—	**$ 2,882.9**	—

(1) Includes total estimated proved reserves of 1.1 MMBOE and a pre-tax PV10% value of $24.5 million in California and total estimated proved reserves of 0.8 MMBOE and a pre-tax PV10% value of $10.5 million in Canada.

(2) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. We believe pre-tax PV10% is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our 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 natural 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.

We expect to continue to build on our successful acquisition track record and seek property acquisitions that complement our existing core properties. Additionally, we believe that our significant drilling inventory, combined with our operating experience and efficient cost structure, provides us with significant organic growth opportunities. During 2005, we incurred $1.2 billion in acquisition, exploration and development activities, including $223.6 million for the drilling of 308 gross (180.5 net) wells. Of these new wells, 283 resulted in productive completions and 25 were unsuccessful, yielding a 92% success rate. We have budgeted approximately $360.0 million for development and exploration drilling expenditures in 2006. Based on current availability and access to drilling rigs in our areas of operations, we do not anticipate significant delays due to rig availability during 2006.

Celero Acquisitions

In 2005, we acquired from Celero Energy, LP ("Celero") the operated interests in two producing oil and natural gas fields as well as positions in several other smaller fields, totaling 122.3 MMBOE of estimated proved reserves as of the effective date of the acquisitions. On August 4, 2005, we acquired properties in the Postle field, located in the Oklahoma Panhandle, and on October 4, 2005, we acquired properties in the North Ward Estes field and certain other smaller fields, located in the Permian Basin.

The effective date of both acquisitions was July 1, 2005. The total purchase price was $802.2 million comprised of $343.0 million in cash paid at the closing of the Postle properties and $442.0 million in cash paid at the closing of the North Ward Estes properties along with 441,500 shares of our common stock. We funded the acquisition of the Postle properties through borrowings under the credit agreement of Whiting Oil and Gas Corporation, our wholly-owned subsidiary. We funded the acquisition of the North Ward Estes properties with the net proceeds from the private placement of our 7% Senior Subordinated Notes due 2014 and our common stock offering, both of which closed on October 4, 2005.

Other 2005 Acquisitions

Limited Partnerships Interests. On June 23, 2005, we completed our acquisition of all of the limited partnership interests in three institutional partnerships managed by our wholly-owned subsidiary Whiting Programs, Inc. The purchase price was $30.5 million for estimated proved reserves of approximately 2.9 MMBOE as of the acquisition effective date, resulting in a cost of $10.52 per BOE of estimated proved reserves. The partnership properties are located in Louisiana, Texas, Arkansas, Oklahoma and Wyoming. The average daily production from the properties was 0.7 MBOE/d as of the effective date of the acquisition. We funded the acquisition using cash on hand.

Green River Basin. On March 31, 2005, we completed our acquisition of 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 approximately 8.4 MMBOE as of the acquisition effective date, resulting in a cost of $7.74 per BOE of estimated proved reserves. We operate approximately 95% of the average daily production from the properties, which was 1.1 MBOE/d as of the effective date of the acquisition. We funded the acquisition through borrowings under Whiting Oil and Gas Corporation's credit agreement.

Business Strategy

Our goal is to generate meaningful growth in both production and free cash flow by investing in oil and natural gas projects with attractive rates of return on capital employed. To date, we have achieved this goal largely through the acquisition of additional reserves 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 natural 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:

Developing and Exploiting Existing Properties. Our existing property base and our acquisitions over the past two years have provided us with significant low-risk opportunities for exploitation and development drilling. As of December 31, 2005, we have identified a drilling inventory of approximately 1,400 gross wells that we believe will add substantial production over the next five years. Our drilling inventory consists largely of the development of our proved undeveloped reserves on which we have spent significant time evaluating the costs and expected results. Additionally, we have several opportunities to apply enhanced recovery techniques that we expect will increase proved reserves and extend the productive lives of our mature fields. We anticipate significant increases in production from the Celero properties through the use of secondary and tertiary recovery techniques, including water and CO_2 floods.

Growing Through Accretive Acquisitions. Since our initial public offering in November 2003, we have announced eleven acquisitions totaling 206.3 MMBOE of estimated total proved reserves. 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. As a result of our disciplined approach, we have achieved significant growth in our core areas at an average cost of $6.94 per BOE of proved reserves through these eleven acquisitions.

Pursuing High-Return Organic Reserve Additions. We plan to allocate approximately 55% of our $360.0 million capital budget for 2006 to the development of our existing proved reserves. The remaining 45% will be invested in higher risk drilling, including field extensions drilled outside the current limits of our development projects as well as new exploration, which we believe will add substantially to our proved reserves and future cash flow. Although exploration has not been the most significant driver of our growth, we believe that we can prudently and successfully grow in part through exploratory activities given our technical team's experience with advanced drilling techniques and our expanded base of operations. We own interests in approximately 615,500 gross (354,200 net) undeveloped acres as well as additional rights to deeper horizons within many of our developed acreage positions.

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. To support cash flow generation on our existing properties and secure acquisition economics, we periodically enter into derivative contracts. Typically, we use cost less 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, 2005, we had interests in 8,942 gross (3,443 net) productive wells across 1,032,500 gross (484,700 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 for success in executing our strategy because we are not dependent on any particular producing regions or geological formations. As a result of the Celero acquisitions, we have enhanced the production stability and reserve life of our developed reserves. Additionally, the Celero properties contain identifiable growth opportunities to significantly increase production in the near and intermediate term.

Experienced Management Team. Our management team averages over 25 years of experience in the oil and natural 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 25 years of experience in the evaluation, acquisition and operational assimilation of oil and natural 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 1,294 square miles of 3-D seismic data, digital well logs and other subsurface information. This data is analyzed with state of the art geophysical and geological computer resources dedicated to the accurate and efficient characterization of the subsurface oil and natural gas reservoirs that comprise our asset base. Computer applications enable us to quickly generate reports and schematics on our wells. In addition, our information systems enable us to update our production databases through daily uploads from hand held computers in the field. This commitment to technology has increased the productivity and efficiency of our field operations development activities.

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Proved Reserves

Our estimated proved reserves as of December 31, 2005 are summarized in the table below.

	Oil (MMBbl)	Natural Gas (Bcf)	Total (MMBOE)	% of Total Proved	Future Capital Expenditures (In thousands)
Permian Basin:					
PDP	34.8	46.1	42.5	35%	$ 0.2
PDNP	12.2	5.9	13.2	11%	66.8
PUD	58.8	32.5	64.2	54%	431.0
Total Proved	**105.8**	**84.5**	**119.9**	**100%**	**$ 498.0**
Rocky Mountains (1):					
PDP	34.2	64.3	45.0	77%	$ 1.4
PDNP	1.3	4.7	2.0	4%	3.1
PUD	5.2	36.5	11.3	19%	112.9
Total Proved	**40.7**	**105.5**	**58.3**	**100%**	**$ 117.4**
Mid-Continent:					
PDP	23.2	30.1	28.2	53%	$ 12.9
PDNP	1.7	2.3	2.1	4%	13.9
PUD	21.7	9.5	23.3	43%	193.3
Total Proved	**46.6**	**41.9**	**53.6**	**100%**	**$ 220.1**
Gulf Coast:					
PDP	1.9	46.6	9.7	53%	$ 3.3
PDNP	1.5	8.3	2.9	16%	3.1
PUD	0.8	28.9	5.6	31%	45.3
Total Proved	**4.2**	**83.8**	**18.2**	**100%**	**$ 51.7**
Michigan:					
PDP	0.6	54.7	9.8	71%	$ 0.0
PDNP	0.5	4.4	1.2	9%	1.0
PUD	0.8	11.6	2.6	20%	20.9
Total Proved	**1.9**	**70.7**	**13.6**	**100%**	**$ 21.9**
Total Company:					
PDP	94.7	241.8	135.2	51%	$ 17.8
PDNP	17.2	25.6	21.4	8%	87.9
PUD	87.3	119.0	107.0	41%	803.4
Total Proved	**199.2**	**386.4**	**263.6**	**100%**	**$ 909.1**

(1) Includes total estimated proved reserves of 1.1 MMBOE in California and 0.8 MMBOE in Canada.

Marketing and Major Customers

We principally sell our oil and natural 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 natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted. During 2005, sales to Teppco Crude Oil LLC accounted for 10% of our total oil and natural gas production revenue. During 2004 and 2003, no single customer was responsible for generating 10% or more of our total oil and natural gas sales.

Title to Properties

Our properties are subject to customary royalty interests, liens under indebtedness, liens incident to operating agreements, liens for current taxes and other burdens, including other mineral encumbrances and restrictions. Whiting Oil and Gas Corporation's 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 natural gas industry, minimal investigation of title is made at the time of acquisition of undeveloped properties. In most cases, we investigate title and obtain title opinions from counsel only when we acquire producing properties or before commencement of drilling operations.

Competition

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural 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 natural gas industry.

Regulation

Regulation of Transportation and Sale 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.

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.

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.

Regulation of Production

The production of oil and natural 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 natural gas properties, the establishment of maximum allowable rates of production from oil and natural 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 natural 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, natural 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 natural gas leases through regulations issued under applicable statutory authority. State regulatory authorities establish similar standards for royalty payments due under state oil and natural 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 natural 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 natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental Regulations

General. Our oil and natural 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 natural gas industry increases the cost of doing business and consequently affects its profitability.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent and costly material handling, storage, transport, disposal or cleanup requirements could materially and adversely affect our operations and financial position, as well as those of the oil and natural 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 natural 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 natural 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.

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 million while the liability limit for offshore facilities is the payment of all removal costs plus up to $75 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 million ($10 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 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 natural 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 natural gas industry into certain coastal and offshore waters without an individual or general National Pollutant Discharge Elimination System discharge permit

Historically, the EPA had regulations under the authority of the CWA that required certain oil and natural gas exploration and production projects to obtain permits for construction projects with storm water discharges. However, the EPAct of 2005 nullified most of the EPA regulations that required permitting of oil and natural gas construction projects. There are still some States that regulate the discharge of storm water from oil and natural 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. 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 restricts the emission of air pollutants from many sources, including oil and natural 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.

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 natural 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.

Employees

As of December 31, 2005, we had 309 full-time employees, including 24 senior level geoscientists and 27 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

You should carefully consider each of the risks described below, 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 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 natural gas prices may adversely affect our business, financial condition or results of operations.

The price we receive for our oil and natural 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 natural 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 the following:

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

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil or natural 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 natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders.

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

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read "— Reserve estimates depend on many assumptions that may turn out to be inaccurate . . ." 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, and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices; and
- title problems.

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 future acquisitions and our recently completed acquisitions:

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

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

Of the reserves that we acquired from Celero in the North Ward Estes field, 62% are proved undeveloped reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO_2 injection installations, the success of which is less predictable than traditional development techniques. 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. During 2005, we completed four separate acquisitions of producing properties with a combined purchase price of $897.7 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 133.7 MMBOE, representing an average cost of approximately $6.71 per BOE of estimated proved reserves. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;
- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform 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 natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

Accounting rules require that we review periodically the carrying value of our oil and natural 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 natural 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 and business prospects.

As of December 31, 2005, we had $260.0 million in outstanding consolidated indebtedness under Whiting Oil and Gas Corporation’s credit agreement with $527.5 million of available borrowing capacity, as well as $615.1 million of Senior Subordinated Notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation’s credit agreement.

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

- increasing our vulnerability to general adverse economic and industry conditions and detracting from our ability to withstand successfully a downturn in our business or the economy generally;
- 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 Corporation’s 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 Corporation’s credit agreement is periodically redetermined based on an evaluation of our reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our bank debt.

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, equity financings or proceeds from the sale of assets may not be available to pay or refinance such debt. The terms of our debt, including Whiting Oil and Gas Corporation's credit agreement, may also prohibit us from taking such actions. Factors that will affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions and our market value and operating performance at the time of such offering or other financing. We may not be able to successfully complete any such offering, refinancing or sale of assets.

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

The indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation's credit agreement contain various restrictive covenants that limit our management's discretion in operating our business. 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 restrict subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, Whiting Oil and Gas Corporation's credit agreement 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 Corporation's credit agreement or any other subsequent financing agreements, a default may allow the creditors, if the agreements so provide, to accelerate the related indebtedness as well as any other indebtedness to which a cross-acceleration or cross-default provision applies. In addition, lenders may be able to terminate any commitments they had made to make available further funds.

Our development and exploration 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 natural gas and oil reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural 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 natural gas we are able to produce from existing wells;
- the prices at which oil and natural 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 natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, then 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 exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas and oil 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 natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown or incorporated by reference in this prospectus.

In order to prepare our estimates, we must project production rates and timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Therefore, estimates of oil and natural gas reserves are inherently imprecise.

Actual future production, oil and natural gas prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves most likely will vary from our estimates. Any significant variance could materially affect the estimated quantities and present value of reserves shown or incorporated by reference in this prospectus. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

You should not assume that the present value of future net revenues from our proved reserves referred to in this prospectus is the current market value of our estimated oil and natural 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, 2005 would have decreased from $2,882.9 million to $2,867.8 million. If oil prices decline by $1.00 per barrel, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2005 would have decreased from $2,882.9 million to $2,818.1 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 natural 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 natural 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.

Prospects that we decide to drill may not yield oil or natural 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 natural 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 natural 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 natural gas will be present or, if present, whether oil or natural 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 incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

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

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

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

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

If we do not operate the properties in which we own an interest, we do not have control over normal operating procedures, expenditures or future development of underlying properties. The failure of an operator of our wells to adequately perform operations, or an operator's breach of the applicable agreements, could reduce our production and revenues. The success and timing of our drilling and development activities on properties operated by others therefore depends upon a number of factors outside of our control, including the operator's timing and amount of capital expenditures, expertise and financial resources, inclusion of other participants in drilling wells, and use of technology. Because we do not have a majority interest in most wells we do not operate, we may not be in a position to remove the operator in the event of poor performance.

Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil, 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. As a result, 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 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 data without having an opportunity to attempt to benefit from those expenditures.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part 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 of inadequacy or unavailability of natural gas pipeline or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver to market.

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

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

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

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 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 the environmental laws and regulations.

Our oil and natural 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. 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 natural gas industry in general. 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.

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

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

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

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, our Chairman, President and Chief Executive Officer, James T. Brown, our Vice President, 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 on a timely basis our exploration and development plans within our budget.

Shortages or the high cost of drilling rigs, equipment, supplies or personnel could delay or adversely affect our development and exploration operations, which could have a material adverse effect on our business, financial condition, results of operations or cash flows.

Competition in the oil and natural 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 natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural 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 natural 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 natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income.

We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions have to date consisted of financially settled crude oil and natural gas forward sales contracts with major financial institutions. As of December 31, 2005, we have contracts maturing in 2006 covering the sale of between 1,500,000 and 1,600,000 MMbtu of natural gas per month and between 410,000 and 450,000 barrels of oil per month. Whiting Oil and Gas Corporation's credit agreement required us to hedge at least 55% of our total forecasted PDP production from the Postle properties and the North Ward Estes properties for the period through March 31, 2007 for natural gas and December 31, 2008 for oil. These hedges were put in place during the third quarter of 2005. See "Quantitative and Qualitative Disclosure about Market Risk — Commodity 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 natural 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 would have otherwise received from increases in the price for oil and natural gas. Furthermore, if we do not engage in hedging transactions, then we may be more adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requirements.

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, 2005, the Permian Basin region contributed 119.9 MMBOE (88% crude oil) of estimated proved reserves to our portfolio of operations, which represented 45% of our total estimated proved reserves. Approximately 95% 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, 2005, there were approximately 636 producing wells and 667 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. As part of this acquisition, we also acquired the rights to deeper horizons under 34,590 gross acres in the North Ward Estes field. The North Ward Estes properties produced at an estimated average net daily rate of 4,930 barrels of oil (including NGLs) and 3,700 Mcf of natural gas during the month of December 2005. In the North Ward Estes field, the estimated proved reserves as of December 31, 2005 were approximately 22% PDP, 16% PDNP and 62% 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 plan to expand the waterflood operations in the field during 2006 as well as reinitiate a CO_2 project in 2007.

Included in the North Ward Estes acquisition were interests in certain other fields encompassing approximately 51,200 gross acres (33,000 net). These other fields include approximately 800 oil and natural gas wells within the Permian Basin of Texas and New Mexico. These properties produced at an estimated average net daily rate of 810 barrels of oil (including NGLs) and 1,900 Mcf of natural gas during the month of December 2005.

Parkway (Delaware) Unit. We own a 61.5% non-operated working interest in the Parkway (Delaware) Unit, a waterflood concentrated on 920 gross acres in Eddy County, New Mexico. Enhancements to the waterflood for 2005 involved continuation of the project to convert existing five-spot patterns to nine-spot patterns with the drilling of nine wells in 2005.

Would Have Field. We own an approximately 87% operated working interest in the Would Have field in Howard County, Texas, currently producing from 56 wells. Discovered in 2001, this field produces from two sub-units of the Clearfork Formation, the Would Have and the Dillard Limestones. We expect to expand the successful waterflood initiated in the western half of the field in May 2004 to the eastern portion of the field in 2006. Efforts are underway to identify additional locations outside of the main Would Have field reservoir development.

Keystone South Field. Our 100% working interest in the Keystone field provides a solid production base plus a portfolio of exploitation opportunities. The property covers a surface area of 7,260 acres in Winkler County, Texas. Most current production comes from the Clearfork Formation, with additional production from the Wichita, Wolfcamp, Devonian, Silurian, McKee and Ellenburger. The 2005 drilling program at Keystone South targeted the shallow Clearfork and Wichita-Albany formations with nine wells. Targeted for 2006, development of deeper pay horizons should benefit from a 3-D seismic survey that was conducted in 2005.

Rocky Mountain Region

Our Rocky Mountain operations include assets in the states of North Dakota, Montana, Colorado, Utah, Wyoming, California and in the Canadian province of Alberta. As of December 31, 2005, our estimated proved reserves in the Rocky Mountain region were 58.3 MMBOE (70% oil), which represented 22% of our total estimated proved reserves. The majority of our reserves in the Rocky Mountain region are in North Dakota and Wyoming. Approximately 43% of the proved reserves of our Rocky Mountain operations are related to assets in North Dakota. Our Canadian assets consist solely of our 50% working interest in the Cessford field located in southern Alberta, with total proved reserves of 0.8 MMBOE.

Billings Nose Drilling Program. Over the last five years, we have established a high concentration of producing wells and approximately 33,000 acres 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. During the last two years, we have acquired 99 square miles of 3D 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. In the fourth quarter of 2005 we drilled two new natural gas discoveries in the Red River Formation, and a new Bakken horizontal well which had favorable results during drilling operations and is currently being completed. For the remainder of 2006, we expect to drill up to six Mission Canyon wells in the Big Stick and North Elkhorn Ranch fields, up to six Bakken horizontal wells, and three to six Red River wells. In addition to the Billings Nose area, we have acquired approximately 100,000 acres prospective in the Bakken and Red River formations in other parts of North Dakota.

Nisku A Drilling Program. We made a significant exploration discovery in 2004 in western Billings County, North Dakota in the Nisku A zone. After this exploration success, we ramped up activity in the area and drilled a total of ten wells by the end of 2004. During 2005 we expanded our program by drilling eight casing-exit wells. We also drilled or participated in 13 grass-roots horizontal wells. As a consequence, the play is now well into the development stage with a total of nine remaining wells planned for 2006. We have determined that much of the area we have defined in our drilling program has strong potential for enhanced oil recovery through waterflood and we are formulating plans for potential implementation.

The “A” zone of the Nisku Formation is a thin, two to four foot dolomite bed encased between two impermeable anhydrite beds creating a regional stratigraphic trap that is present over more than 100 square miles. These geologic conditions make the Nisku A an ideal horizontal drilling candidate. We currently hold 33,000 prospective net acres in Billings and Golden Valley Counties, North Dakota.

Green River Basin—Siberia Ridge. Siberia Ridge is within the greater Wamsutter Arch area of Sweetwater County, Wyoming and produces from a continuous-phase natural gas accumulation in the Cretaceous Almond Formation at 10,500 feet. Our properties in the Siberia Ridge field resulted from the acquisition of Equity Oil Company in 2004 and were further enhanced by a producing property acquisition in early 2005. 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. Our development program commenced in mid-2005 with the drilling of five new wells. We have implemented a focused effort on the identification, selective perforation and stimulation of the various natural gas productive zones within the Almond Formation in order to optimize production. Completion operations are currently underway with encouraging initial rates. We plan to drill up to nine additional wells in 2006.

California. As of December 31, 2005, our California operations contributed 1.1 MMBOE (100% natural gas) of net proved reserves to our portfolio of operations, which represented 0.4% of our total estimated proved reserves. Our assets in this region are located in the Sacramento Basin of California, and the Todhunters Lake and Willow Slough fields of Yolo County, California. We also own non-operated working interests in Colusa and Glenn Counties, California.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. The majority of the proved value within our Mid-Continent operations is related to properties in Postle.

Postle Field. The Postle field, located in Texas County, Oklahoma, includes five producing units and one producing lease covering a total of approximately 25,600 gross acres (24,223 net) with working interests of 94% to 100%. Three of the units are currently under CO_2 enhanced recovery projects. As of December 31, 2005, there were 91 producing wells and 105 injection wells completed in the Morrow zone at 6,100 feet. The Postle properties produced at an estimated average net daily rate of 4,190 Bopd (including NGLs) and 660 Mcf/d of natural gas during the month of December 2005. In the Postle field, the estimated proved reserves as of December 31, 2005 were 47% PDP, 4% PDNP and 49% PUD.

The Postle field was initially developed in the early 1960’s and unitized for waterflood in 1967. Enhanced recovery projects using CO_2 were initiated in 1995 and continue in three of the five units. We plan to expand the current CO_2 projects into the rest of the units. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells. This expansion work is underway, with two drilling rigs and six workover rigs currently active in the field.

In connection with the acquisition of the Postle properties, we acquired 100% ownership 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 reinjected into the producing formation. Plans are underway to increase the plant capacity from its current capacity of 43 MMcf/d to 83 MMcf/d by 2007 to support the expanded CO_2 injection projects.

We also acquired a 60% interest in the 120 mile TransPetco operated CO_2 transportation pipeline serving the Postle field, thereby assuring the delivery of CO_2 at a fair tariff. A long-term CO_2 purchase agreement was executed in 2005 with a major integrated oil and natural gas company 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, 2005, the Gulf Coast region contributed 18.2 MMBOE (23% oil) of proved reserves to our portfolio of operations, which represented 7% of our total estimated proved reserves. Approximately 84% of the proved reserves of our Gulf Coast operations are related to properties in Texas.

*Stuart City Reef Trend***.** In June 2001, we acquired an average 65% working interest in five fields in the Stuart City Reef Trend: Word North, Yoakum, Kawitt, Sweet Home, and Three Rivers. 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.

In late 2003 we began a combination development and exploration program targeting multiple sandstone natural gas reservoirs within the Wilcox Formation. We have been active in this area, drilling nine wells in 2005 and are planning an additional six in 2006. In addition, we are currently planning to conduct a 40 square mile 3-D seismic program designed to expand this play into new areas. Relatively low drilling costs, multiple objective natural gas reservoirs and predictable reserves have combined to make this a low risk economic play with significant upside.

During the third quarter of 2005, we resumed our Edwards horizontal drilling program with two new wells in the Word North field and are currently completing the second of three Edwards wells in the Kawitt field. Initial results from these wells have been in line with our expectations.

Vicksburg Trend. Our holdings in the Vicksburg and Frio Trends are concentrated primarily in the South Midway field (operated by EOG Resources) in San Patricio County, Texas and the Agua Dulce field. During 2005, operations were active in these areas where we drilled or participated in eleven new wells targeting multiple natural gas productive sands in the Vicksburg and Frio Formations at depths between 10,000 and 14,500 feet. Results from this program have encouraged us to drill up to five additional wells in South Midway and up to three wells in Agua Dulce during 2006.

Michigan Region

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 natural gas production located in the central and southern parts of the state. We also operate the West Branch and Stoney Point natural gas processing plants. These plants are in excellent 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 natural gas projects with proved producing reserves and ongoing development drilling. During 2005, we participated in the drilling and completion of 20 Antrim Shale wells. In 2006, we plan to continue to pursue the development drilling opportunities including the evaluation of horizontal drilling.

Conventional Production. Our conventional production is primarily from the Prairie du Chien, Glenwood and Trenton Black River Formations located in central and southern Michigan. We own interests in over 20 fields in this area, of which we operate seven.

During 2005 we drilled two Glenwood / Prarie du Chien (“PdC”) wells in the Clayton field. Both of these wells encountered hydrocarbons in the Middle interval of the PdC which had not previously produced in addition to behind-pipe reserves in the Upper PdC, the primary producing interval. We have been very encouraged by the results. We are in the process of working with a drilling contractor to move another drilling rig into the state of Michigan. Our plans at this point are to use this rig to drill both operated wells and wells operated by others in which we own an interest.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2005 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.

	Developed Acreage		Undeveloped Acreage		Total Acreage	
	Gross	Net	Gross	Net	Gross	Net
California	22,822	9,763	3,658	373	26,480	10,136
Colorado	51,956	28,481	30,702	6,204	82,658	34,685
Kansas	850	561	76,751	75,408	77,601	75,969
Louisiana	38,135	10,566	5,338	2,359	43,473	12,925
Michigan	187,756	68,310	7,360	5,852	195,116	74,162
Montana	46,524	12,249	78,606	46,753	125,130	59,002
North Dakota	141,774	76,593	283,629	153,934	425,403	230,527
Oklahoma	63,948	49,426	451	90	64,399	49,516
Texas	328,849	153,596	42,151	30,388	371,000	183,984
Utah	21,156	11,359	36,003	16,206	57,159	27,565
Wyoming	110,776	56,958	49,733	16,166	160,509	73,124
Other*	17,945	6,815	1,081	456	17,087	7,271
Total	1,032,491	484,677	615,463	354,189	1,646,015	838,866

* Other includes Alabama, Arkansas, Canada, Mississippi, New Mexico and South Dakota

Production History

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

	Year Ended December 31,		
	2005	2004	2003
Oil production (MMbbls)	7.0	3.7	2.6
Natural gas production (Bcf)	30.3	25.1	21.6
Total production (MMBOE)	12.1	7.9	6.2
Daily production (MBOE/d)	33.1	21.6	17.0
Average sales prices:			
Natural gas (per Mcf)	$ 7.03	$ 5.56	$ 4.78
Effect of natural gas hedges on average price (per Mcf)	$ (0.47)	$ —	$ (0.30)
Natural gas net of hedging (per Mcf)	$ 6.56	$ 5.56	$ 4.48
Oil (per Bbl)	$ 51.26	$ 38.72	$ 27.50
Effect of oil hedges on average price (per Bbl)	$ (2.72)	$ (1.33)	$ (0.37)
Oil net of hedging (per Bbl)	$ 48.54	$ 37.39	$ 27.13
Per BOE data:			
Sales price (net of hedging)	$ 44.70	$ 35.23	$ 27.00
Lease operating expenses	$ 9.24	$ 6.90	$ 6.96
Production taxes	$ 2.99	$ 2.16	$ 1.74
Depreciation, depletion and amortization expenses	$ 8.08	$ 6.90	$ 6.66
General and administrative expenses	$ 2.53	$ 2.45	$ 2.10

Productive Wells

The following table presents our ownership at December 31, 2005 in productive oil and natural 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	3,513	1,511	194	129	3,707	1,640
Rocky Mountains	2,026	476	421	170	2,447	646
Mid-Continent	504	298	204	84	708	382
Gulf Coast	135	56	835	266	970	322
Michigan	77	58	1,033	395	1,110	453
Total	6,255	2,399	2,687	1,044	8,942	3,443

(1) 77 wells are multiple completions. These 77 wells contain a total of 167 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 the results of 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
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
2004:						
Development	157	7	164	73.4	3.7	77.1
Exploratory	3	2	5	1.5	0.2	1.7
Total	160	9	169	74.9	3.9	78.8
2003:						
Development	64	5	69	20.9	2.3	23.2
Exploratory	—	3	3	—	1.6	1.6
Total	64	8	72	20.9	3.9	24.8

Item 3. Legal Proceedings

In the ordinary course of business, we are a claimant or a defendant in various legal proceedings. In the opinion of our management, we do not have any litigation pending or threatened that is material.

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 2005.

EXECUTIVE OFFICERS OF THE REGISTRANT

The following table sets forth certain information, as of February 15, 2006, regarding the executive officers of Whiting Petroleum Corporation:

Name	Age	Position
James J. Volker	59	Chairman, President and Chief Executive Officer
D. Sherwin Artus	68	Senior Vice President
James T. Brown	53	Vice President, Operations
Bruce R. DeBoer	53	Vice President, General Counsel and Corporate Secretary
J. Douglas Lang	56	Vice President, Reservoir Engineering/Acquisitions
Patricia J. Miller	68	Vice President, Human Resources
David M. Seery	51	Vice President, Land
Michael J. Stevens	40	Vice President and Chief Financial Officer
Mark R. Williams	49	Vice President, Exploration and Development
Brent P. Jensen	36	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 natural gas industry. Mr. Volker has a degree in finance from the University of Denver, a MBA from the University of Colorado and has completed H. K. VanPoolen and Associates' course of study in reservoir engineering.

D. Sherwin Artus joined us in January 1989 as Vice President of Operations and became Executive Vice President and Chief Operating Officer in July 1999. In January 2000, he was appointed President and Chief Executive Officer and a director. In January 2002, he became Senior Vice President. He has been in the oil and natural gas business for over forty years. Mr. Artus holds a Bachelor's Degree in geologic engineering and a Master's Degree in mining engineering from the South Dakota School of Mines and Technology.

James T. Brown joined us in May 1993 as a consulting engineer. In March 1999, he became Operations Manager and, in January 2000, he became Vice President of Operations. Mr. Brown has thirty years of oil and natural 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 a MBA from the University of Denver.

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 natural gas exploration and production company. Mr. DeBoer has over 20 years of experience in managing the legal departments of several independent oil and natural 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.

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 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 a 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.

Patricia J. Miller joined us in April 1980 as Corporate Secretary and as Secretary to our President, becoming Director of Human Resources in May 1994. In November 2001, she was appointed Vice President of Human Resources. She served as Corporate Secretary until January 2005. Mrs. Miller attended business school at Otero Junior College in LaJunta, Colorado and at Texas A & I in Kingsville, Texas.

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-four 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 as Chief Financial Officer, Controller, Secretary and Treasurer at Inland Resources Inc., a company engaged in oil and natural 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-three 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 Treasurer in January 2006. He was previously a Senior Manager with PricewaterhouseCoopers L.L.P. in Houston, Texas, where he held various positions in their oil and gas audit practice since joining that firm in 1994, including a four year assignment in their Moscow, Russia office and almost three years in their Milan, Italy office. He has 12 years of oil and gas accounting experience and is a Certified Public Accountant. Mr. Jensen holds a Bachelor of Arts degree with an emphasis on 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, 2005		
Fourth Quarter (Ended December 31, 2005)	$ 44.91	$ 36.77
Third Quarter (Ended September 30, 2005)	$ 46.17	$ 36.39
Second Quarter (Ended June 30, 2005)	$ 43.20	$ 28.19
First Quarter (Ended March 31, 2005)	$ 46.30	$ 27.76
Fiscal Year Ended December 31, 2004		
Fourth Quarter (Ended December 31, 2004)	$ 34.22	$ 27.52
Third Quarter (Ended September 30, 2004)	$ 31.20	$ 21.85
Second Quarter (Ended June 30, 2004)	$ 27.59	$ 21.50
First Quarter (Ended March 31, 2004)	$ 23.94	$ 18.45

On February 15, 2006, there were 921 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 results of operations, financial condition, capital requirements and investment opportunities. In addition, the agreements governing our indebtedness prohibit us from paying dividends.

Item 6. Selected Financial Data

The consolidated income statement information for the years ended December 31, 2005, 2004 and 2003 and the balance sheet information at December 31, 2005 and 2004 are derived from our audited financial statements included elsewhere in this report. The consolidated income statement information for the years ended December 31, 2002 and 2001 and the balance sheet information at December 31, 2003, 2002 and 2001 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: Green River Basin, March 31, 2005; Limited Partnership Interests, June 23, 2005; Postle Properties, August 4, 2005; and North Ward Estes and Ancillary Properties, October 4, 2005.

	Year Ended December 31,				
	2005	2004	2003	2002	2001
	(dollars in millions except per share data)				
Consolidated Income Statement Information:					
Revenues and other income:					
Oil and gas sales	$ 573.2	$ 281.1	$ 175.7	$ 122.7	$ 125.2
Gain (loss) on oil and gas hedging activities	(33.4)	(4.9)	(8.7)	(3.2)	2.3
Gain on sale of oil and gas properties	—	1.0	—	1.0	11.7
Gain on sale of marketable securities	—	4.8	—	—	—
Interest income and other	0.6	0.1	0.3	—	0.2
Total revenues and other income	$ 540.4	$ 282.1	$ 167.3	$ 120.5	$ 139.4
Costs and expenses:					
Lease operating	$ 111.6	$ 54.2	$ 43.2	$ 32.9	$ 29.8
Production taxes	36.1	16.8	10.7	7.4	6.5
Depreciation, depletion and amortization (1)	97.6	54.0	41.2	43.6	26.9
Exploration and impairment	16.7	6.3	3.2	1.8	0.8
General and administrative	30.6	19.2	13.0	10.3	9.4
Change in Production Participation Plan liability	9.7	1.7	(0.2)	1.7	1.5
Phantom equity plan (2)	—	—	10.9	—	—
Interest expense	42.0	15.9	9.2	10.9	10.2
Total costs and expenses	$ 344.3	$ 168.1	$ 131.2	$ 108.6	$ 85.1
Income before income taxes and cumulative change in accounting principle	$ 196.1	$ 114.0	$ 36.1	$ 11.9	$ 54.3
Income tax expense (3)	74.2	44.0	13.9	4.2	13.1
Income before cumulative change in accounting principle	121.9	70.0	22.2	7.7	41.2
Cumulative change in accounting principle (4)	—	—	3.9	—	—
Net income	$ 121.9	$ 70.0	$ 18.3	$ 7.7	$ 41.2
Income per common share before cumulative change in accounting principle, basic	$ 3.89	$ 3.38	$ 1.18	$ 0.41	$ 2.20
Income per common share before cumulative change in accounting principle, diluted	$ 3.88	$ 3.38	$ 1.18	$ 0.41	$ 2.20
Net income per common share, basic	$ 3.89	$ 3.38	$ 0.98	$ 0.41	$ 2.20
Net income per common share, diluted	$ 3.88	$ 3.38	$ 0.98	$ 0.41	$ 2.20
Other Financial Information:					
Net cash provided by operating activities	$ 330.4	$ 134.1	$ 91.9	$ 62.6	$ 62.3
Net cash used in investing activities	$ 1,126.9	$ 524.4	$ 47.6	$ 157.5	$ 86.5
Net cash provided by financing activities	$ 805.2	$ 338.4	$ 4.4	$ 98.7	$ 23.9
Ratio of earnings to fixed charges (5)	5.64x	8.01x	4.85x	2.08x	6.10x
Capital expenditures	$ 1,126.9	$ 530.6	$ 47.6	$ 165.4	$ 99.6

	As of December 31,				
	2005	2004	2003	2002	2001
	(dollars in millions)				
Balance Sheet Information:					
Total assets	$ 2,235.2	$ 1,092.2	$ 536.3	$ 448.5	$ 319.8
Total debt	$ 875.1	$ 328.4	$ 188.0	$ 265.5	$ 163.6
Stockholders' equity	$ 997.9	$ 612.4	$ 259.6	$ 122.8	$ 111.5

(1) We reduced the amount of our abandonment liability estimate from $13.0 million at December 31, 2000 to $4.0 million at December 31, 2001 as a result of receiving a revised and more detailed dismantlement plan from our dismantlement operator. This $9.0 million change in estimate reduced our depreciation, depletion and amortization expense in our 2001 financial statements as the expense for the abandonment liability had originally been recorded as a depreciation, depletion and amortization expense.

(2) 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.

(3) We generated Section 29 tax credits of $6.6 million in 2001 and $5.4 million in 2002. Section 29 tax credit provisions of the Internal Revenue Code expired as of December 31, 2002. In 2002, we were able to use our $5.4 million of Section 29 tax credits in the consolidated federal income tax return filed by Alliant Energy, but since these credits would not have been used in a stand-alone filing, they were recorded as additional paid-in capital as opposed to a reduction in income tax expense.

(4) 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.

(5) For the purpose of calculating the ratio of earnings to fixed charges, earnings consist of income before income taxes and income from equity investee, fixed charges, distributed income from equity investee 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.

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

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 "should" or the negative thereof or variations thereon or similar terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. Some, but not all, of the risks and uncertainties include: declines in oil or natural gas prices; our level of success in exploitation, exploration, development and production activities; the timing of our exploration and development expenditures, including our ability to obtain drilling rigs; 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 or liabilities associated with acquired properties; inaccuracies of our reserve estimates or our assumptions underlying them; failure of our properties to yield oil or natural gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and natural gas operations; our inability to access oil and natural gas markets due to market conditions or operational impediments; the impact and costs of compliance with laws and regulations governing our oil and natural 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 natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and natural gas industry; risks arising out of our hedging transactions and other risks described under the caption "Risk Factors." We assume no obligation, and disclaim any duty, to update the forward-looking statements in this report.

Overview

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States. Over the last five years, we have emphasized the acquisition of properties that provided current production and significant upside potential through further development. Our drilling activity is directed at this development, specifically on projects that we believe provide repeatable successes in particular fields.

Our combination of acquisitions and development allows us to direct our capital resources to what we believe to be the most advantageous investments. During periods of radically changing prices, we focus our emphasis on drilling and development of our owned properties. When prices stabilize, we generally direct the majority of our capital to acquisitions.

We have historically acquired operated as well as 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 provided a foothold 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 are of the opinion 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 natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

2005 Acquisitions

We completed four separate acquisitions of producing properties during 2005. The combined purchase price for these four acquisitions was $897.7 million for total estimated proved reserves as of the effective dates of the acquisitions of approximately 133.7 MMBOE. Because of our substantial recent 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: 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.

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 from Celero. 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 approximately 82.1 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of approximately $5.58 per BOE of estimated proved reserves. The average daily production from the properties was approximately 4.6 MBOE/d as of the acquisition effective date. We funded the cash portion of the purchase price with the net proceeds from our public offering of common stock and private placement of 7% Senior Subordinated Notes due 2014, both of which closed on October 4, 2005. See below for estimated future development costs.

Postle Properties

On August 4, 2005, we acquired the operated interest in producing oil and natural gas fields located in the Oklahoma Panhandle. The purchase price was $343.0 million for estimated proved reserves of approximately 40.3 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of approximately $8.52 per BOE of estimated proved reserves. The average daily production from the properties was approximately 4.2 MBOE/d as of the acquisition effective date. We funded the acquisition through borrowings under the credit agreement of Whiting Oil and Gas Corporation, our wholly owned subsidiary. See below for estimated future development costs.

The following table presents estimated future development costs for the North Ward Estes and Ancillary Properties and Postle Properties as of December 31, 2005 (in thousands):

	North Ward Estes and Ancillary Properties	Postle Properties	Total
PDP	$ —	$ 12,906	$ 12,906
PDNP	64,782	12,266	77,048
PUD	361,688	186,481	548,169
Total	$ 426,470	$ 211,653	$638,123

Limited Partnership Interests

On June 23, 2005, we completed our acquisition of all of the limited partnership interests in three institutional partnerships managed by our wholly-owned subsidiary Whiting Programs, Inc. The purchase price was $30.5 million for estimated proved reserves of approximately 2.9 MMBOE as of the acquisition effective date, resulting in a cost of $10.52 per BOE of estimated proved reserves. The partnership properties are located in Louisiana, Texas, Arkansas, Oklahoma and Wyoming. The average daily production from the properties was 0.7 MBOE/d as of the effective date of the acquisition. We funded the acquisition using cash on hand.

Green River Basin

Green River Basin. On March 31, 2005, we completed our acquisition of 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 approximately 8.4 MMBOE as of the acquisition effective date, resulting in a cost of $7.74 per BOE of estimated proved reserves. We operate approximately 95% of the average daily production from the properties, which was 1.1 MBOE/d as of the effective date of the acquisition. We funded the acquisition through borrowings under Whiting Oil and Gas Corporation's credit agreement.

Results of Operations

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

	Year Ended December 31,		
	2005	2004	2003
Net production:			
Natural gas (Bcf)	30.3	25.1	21.6
Oil (MMbbls)	7.0	3.7	2.6
Net sales (in millions):			
Natural gas(1)	$ 212.8	$ 139.4	$ 104.4
Oil(1)	$ 360.4	$ 141.7	$ 71.3
Average sales prices:			
Natural gas (per Mcf)	$ 7.03	$ 5.56	$ 4.78
Effect of natural gas hedges on average price (per Mcf)	$ (0.47)	$ —	$ (0.30)
Natural gas net of hedging (per Mcf)	$ 6.56	$ 5.56	$ 4.48
Oil (per Bbl)	$ 51.26	$ 38.72	$ 27.50
Effect of oil hedges on average price (per Bbl)	$ (2.72)	$ (1.33)	$ (0.37)
Oil net of hedging (per Bbl)	$ 48.54	$ 37.39	$ 27.13
Cost and expense (per MBOE):			
Lease operating expenses	$ 9.24	$ 6.90	$ 6.96
Production taxes	$ 2.99	$ 2.16	$ 1.74
Depreciation, depletion and amortization expense	$ 8.08	$ 6.90	$ 6.66
General and administrative expenses	$ 2.53	$ 2.45	$ 2.10

(1) Before consideration of hedging transactions.

Year Ended December 31, 2005 Compared to Year Ended December 31, 2004

Oil and Gas Sales. Our oil and gas sales revenue increased $292.2 million to $573.2 million in 2005. Sales are a function of sales volumes and average sales prices. Our sales volumes increased 54% between periods on a BOE basis. The volume increase resulted primarily from acquisition activities and successful drilling activities over the past year that produced new sales volumes that more than offset natural field production decline. Our production volumes for 2005 were slightly less than anticipated due in part to delays in rig availability that caused delays in our development drilling program and temporary pipeline shut downs and workover activity in the first quarter of 2005. Hurricanes Katrina and Rita caused only minor reductions to our 2005 sales volumes, in that only 16,700 BOE of total estimated production was lost during 2005 due to the hurricanes. Our average price for natural gas sales increased 26% and our average price for crude oil increased 32% between periods.

Loss on Oil and Gas Hedging Activities. We hedged 60% of our natural gas volumes during 2005 incurring a hedging loss of $14.3 million and 32% of our natural gas volumes during 2004 incurring no hedging loss or gain. We hedged 58% of our oil volumes during 2005 incurring a hedging loss of $19.1 million, and 50% of our oil volumes during 2004 incurring a hedging loss of $4.9 million. See Item 7A, "Qualitative and Quantitative Disclosures About Market Risk" for a list of our outstanding oil and natural gas hedges as of February 15, 2006.

Gain on Sale of Marketable Securities. During 2004, we sold all of our holdings in Delta Petroleum, Inc., which trades publicly under the symbol "DPTR". We realized gross proceeds of $5.4 million and recognized a gain on sale of $4.8 million. During 2005, we had no investments in marketable securities.

Gain on Sale of Oil and Gas Properties. During 2004, we sold certain undeveloped acreage in Wyoming. No value had been assigned to the acreage when we acquired it over five years ago. As a result, the recognized gain on sale was equal to the gross proceeds of $1.0 million.

Lease Operating Expenses. Our lease operating expense increased $57.3 million to $111.6 million in 2005 compared to 2004. The increase resulted primarily from costs associated with new property acquisitions over the past year. Our lease operating expense as a percentage of oil and natural gas sales increased slightly from 19% during 2004 to 20% during 2005. Our lease operating expenses per BOE increased from $6.90 during 2004 to $9.24 during 2005. The increase of 34% was mainly caused by higher costs for electric power and increases in the cost of oil field goods and services due to higher demand in the industry. In addition, our lease operating expenses increased on a BOE basis due to the newly acquired Postle and North Ward Estes properties, which had fourth quarter combined operating costs of $12.72 per BOE relating to the secondary and tertiary recovery projects underway on those fields.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in the various taxing jurisdictions. Our production taxes for 2005 and 2004 were 6.3% and 6.0% of oil and natural gas sales, respectively. The increase in tax rates between periods was related to product price increases that eliminate certain exemptions and move us into higher tax tiers in our various tax jurisdictions, which effect was partially offset by lower production taxes on our properties newly acquired in 2005.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (“DD&A”) increased $43.6 million to $97.6 million during 2005 as compared to $54.0 million for 2004. The increase resulted from increased production due to our recent acquisitions and an increase in our DD&A rate. On a BOE basis, the rate increased from $6.90 during 2004 to $8.08 in 2005. The primary factors causing the DD&A rate increase were the higher costs of adding proved developed reserves in 2005, the increase in drilling expenditures including the development of proved undeveloped reserves, the costs of which are not considered for DD&A purposes until incurred, and downward net reserve revisions. Changes to the pricing environment can also positively impact our DD&A rate. Price increases allow for longer economic production lives and corresponding increased reserve volumes and, as a result, lower depletion rates. Price decreases have the opposite effect. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2005	2004
Depletion	$ 93,818	$ 51,424
Depreciation	1,457	832
Accretion of asset retirement obligations	2,364	1,754
Total	$ 97,639	$ 54,010

Exploration and Impairment. Our exploration and impairment costs increased $10.4 million to $16.7 million in 2005 compared to 2004.

	Year Ended December 31,	
	2005	2004
Exploration	$ 14,665	$ 4,177
Impairment	2,034	2,152
Total	$ 16,699	$ 6,329

Higher exploratory costs resulted from seven exploratory dry holes drilled during 2005 totaling $4.0 million, as compared to two exploratory dry holes in 2004 totaling $0.6 million. We also hired additional geological and geophysical personnel to support the increased drilling budget from $79.4 million in 2004 to $223.6 million in 2005. The impairment charge in 2005 relates primarily to unrecoverable costs associated with our investment in the Cherokee Basin of Kansas. The impairment charge in 2004 was for the write down of cost associated with the High Island field located off the coast of Texas.

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

	Year Ended December 31,	
	2005	2004
General and administrative expenses	$ 42,594	$ 25,992
Reimbursements	(11,987)	(6,768)
General and administrative expenses, net	$ 30,607	$ 19,224

General and administrative expenses before reimbursements increased $16.6 million to $42.6 million during 2005 compared to $26.0 million during 2004. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $9.2 million, an increase in the current year cash payment under our Production Participation Plan of $3.3 million and the amortization of restricted stock compensation of $2.9 million. Personnel salary expenses were higher in 2005 due primarily 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 2005 production volumes and higher average sales prices between years. Restricted stock compensation increased due to the additional issuance of restricted stock in 2005 and due to the layering impact of a multiple year vesting schedule. The increase in reimbursements in 2005 was caused by a higher number of operated properties due to acquisitions and drilling activities during the last half of 2004 and 2005. Our net general and administrative expenses on a BOE basis increased 3% between periods from $2.45 to $2.53. As a percentage of oil and natural gas sales, our general and administrative expenses decreased from 6.8% during 2004 to 5.3% during 2005, as general and administrative costs increased at a slower rate than oil and natural gas sales prices.

Change in Production Participation Plan Liability. For the year ended December 31, 2005, this non-cash expense increased $8.0 million to $9.7 million from $1.7 million during 2004. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2006 under its Production Participation Plan. Although payments take place over the life of oil and natural gas properties contributed to the Plan, some properties for over 20 years, we must expense the present value of estimated future payments over the Plan's five year vesting period. During the fourth quarter of 2005, we determined that the expense related to the long-term portion of the Production Participation Plan liability should be presented separately from general and administrative and exploration expenses because of its significance and because the long-term portion of this liability is calculated based on estimated net cash flows to be realized from the future production of oil and natural gas and as such is not currently payable, unlike other general and administrative or exploration expenses. As a result of this reclassification, general and administrative expense and exploration expenses exclude changes in the long-term portion of the Production Participation Plan liability and include only those amounts paid or accrued under the Production Participation Plan that relate to current period oil and natural gas operations. The increase in expense primarily reflects changes to future cash flows estimates due to the effect of a sustained higher price environment and acquisitions during 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 natural gas prices, discount rates and overall market conditions.

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

	Year Ended December 31,	
	2005	2004
Credit Agreement	$ 9,997	$ 5,893
7.25% Senior Subordinated Notes due 2012	9,758	5,957
7.25% Senior Subordinated Notes due 2013	11,165	—
7% Senior Subordinated Notes due 2014	4,186	—
Alliant Energy	138	150
Amortization of debt issue costs and debt discount	4,076	1,666
Capitalized interest	—	(200)
Accretion of tax sharing liability	2,725	2,390
Total interest expense	$ 42,045	$ 15,856

The increase in interest expense was mainly due to the May 2004 issuance of $150.0 million of 7.25% Senior Subordinated Notes due 2012, the April 2005 issuance of $220.0 million of 7.25% Senior Subordinated Notes due 2013, the October 2005 issuance of $250.0 million of 7% Senior Subordinated Notes due 2014, and additional borrowings outstanding under our amended and restated credit agreement. The additional amortization of debt issue costs and debt discount in 2005 was due to the greater number of days that each instrument was outstanding versus the prior year. In August of 2004, $75.0 million of the face amount of the 7.25% Senior Subordinated Notes due 2012 notes were swapped to a floating rate. At November 1, 2005, the floating rate component was set at 6.8% through May 1, 2006.

Our weighted average debt outstanding during 2005 was $553.0 million versus $257.8 million during 2004. Our weighted average effective cash interest rate was 6.4% during 2005 versus 4.7% 2004. 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 7.2% during 2005 versus 5.5% during 2004.

Income Tax Expense. Income tax expense totaled $74.2 million for 2005 and $44.0 million for 2004, resulting in effective income tax rates of 37.8% and 38.6%, respectively. We were able to defer the majority of our cash income tax obligations due to the level of our drilling expenditures in each year. We reported current income tax expense of $8.5 million in 2005 or 11.5% of the tax provision, as compared to $3.9 million or 8.8% of the tax provision in 2004. The lower rate of current income tax expense in 2004 was mainly due to the use of our 2003 net operating loss carryforward in 2004.

Net Income. Net income increased from $70.0 million during 2004 to $121.9 million during 2005. The primary reasons for this increase included 27% higher crude oil and natural gas prices net of hedging between periods and a 54% increase in equivalent volumes sold, which were partially offset by higher lease operating expenses, production taxes, DD&A, exploration and impairment, general and administrative, Production Participation Plan and interest expenses in 2005 resulting from our continued growth.

Year Ended December 31, 2004 Compared to Year Ended December 31, 2003

Oil and Gas Sales. Our oil and natural gas sales revenue increased $105.3 million to $281.1 million in 2004. Our sales volumes increased 27% between periods on a BOE basis. The volume increase resulted from successful drilling and acquisition activities over the past year that produced new sales volumes that more than offset natural field decline. Our average price for natural gas sales increased 16% and our average price for crude oil increased 41% between periods.

Loss on Oil and Gas Hedging Activities. We hedged 32% of our natural gas volumes during 2004 incurring no hedging gains or losses, and 41% of our natural gas volumes during 2003 incurring a hedging loss of $7.7 million. We hedged 50% of our oil volumes during 2004 incurring a hedging loss of $4.9 million, and 8% of our oil volumes during 2003 incurring a loss of $1.0 million.

Gain on Sale of Marketable Securities. During 2004, we sold all of our holdings in Delta Petroleum, Inc., which trades publicly under the symbol "DPTR". We realized gross proceeds of $5.4 million and recognized a gain on sale of $4.8 million. At December 31, 2004, we had no investments in marketable securities.

Gain on Sale of Oil and Gas Properties. During the third quarter of 2004, we sold certain undeveloped acreage in Wyoming. No value had been assigned to the acreage when we acquired it over five years ago. As a result, the recognized gain on sale is equal to the gross proceeds of $1.0 million.

Lease Operating Expenses. Our lease operating expenses per BOE decreased from $6.96 during 2003 to $6.90 during 2004. The decrease was less than 1%, which represented improved operating efficiency more than offsetting price inflation caused by increased demand for goods and services in the industry. Our fourth quarter 2004 lease operating expense per BOE was $6.91, indicating that the seven acquisitions we completed during the third and fourth quarters of 2004 did not significantly affect our rate.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in the various taxing jurisdictions. Our production taxes for 2004 and 2003 were 6.0% and 6.1% of oil and natural gas sales, respectively.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense ("DD&A") increased from $12.8 million to $54.0 million in 2004. The increase resulted from higher production volumes and an increase in the DD&A rate, as well as the effects of our recent acquisitions. On a BOE basis, the rate increased from $6.66 during 2003 to $6.90 in 2004. The increase in rate is primarily due to 2004 property acquisitions, which we purchased at an average cost of $7.38 per BOE, which was higher than our historical rate. Changes to the pricing environment can also impact our DD&A rate. Price increases allow for longer economic production lives and corresponding increased reserve volumes and, as a result, lower depletion rates. Price decreases have the opposite effect. The components of our DD&A expense were as follows (in thousands):

	Year Ended December 31,	
	2004	2003
Depletion	$ 51,424	$ 38,939
Depreciation	832	835
Accretion of asset retirement obligations	1,754	1,482
Total	$ 54,010	$ 41,256

Exploration and Impairment Costs. Our exploration and impairment costs increased $3.1 million to $6.3 million in 2004. The higher exploratory costs were related to our increased purchases of seismic data in 2004 to support our increased drilling budget. The impairment charge represents the write down of cost associated with the High Island field located off the coast of Texas.

	Year Ended December 31,	
	2004	2003
Exploration	$ 4,177	$ 3,186
Impairment	2,152	—
Total	$ 6,329	$ 3,186

General and Administrative Expenses. We report general and administrative expenses net of reimbursements. The components of our general and administrative expenses were as follows:

	Year Ended December 31,	
	2004	2003
General and administrative expenses	$ 26,012	$ 18,621
Reimbursements	(6,768)	(5,631)
General and administrative expenses, net	$ 19,244	$ 12,990

General and administrative expenses before reimbursements increased $7.4 million to $26.0 million during 2004. The largest components of the increase related to higher costs for personnel salaries, benefits and related taxes of $2.7 million, an increase in the current year cash payment related to our Production Participation Plan of $2.7 million and an increase in the amortization of restricted stock compensation of $0.6 million. Personnel salary expenses were higher in 2004 due primarily to an increase in our employee base due to our continued growth. The increased cost of the Production Participation Plan was caused primarily by higher production volumes and higher oil and natural gas sales prices between years. We recognized restricted stock compensation expense in 2004 but not in 2003, since this was the first year that we issued restricted stock and incurred an amortization charge. On a BOE basis, the increase between years was from $2.10 to $2.45. The increase in reimbursements was caused by a higher number of operated properties due to 2004 property acquisitions and was also caused by an increase in development drilling.

Change in Production Participation Plan Liability. For the year ended December 31, 2004, this non-cash expense increased $1.9 million. This expense represents the change in the vested present value of estimated future payments to be made to participants after 2005 under its Production Participation Plan. Although payments take place over the life of oil and natural gas properties contributed to the Plan, some properties for over 20 years, we must expense the present value of estimated future payments over the Plan's five year vesting period. During the fourth quarter of 2005, we determined that the expense related to the long-term portion of the Production Participation Plan liability should be presented separately from general and administrative and exploration expenses because of its significance and because the long-term portion of this liability is calculated based on estimated net cash flows to be realized from the future production of oil and natural gas and as such is not currently payable, unlike other general and administrative or exploration expenses. As a result of the reclassification, general and administrative expense and exploration expenses exclude changes in the long-term portion of the Production Participation Plan liability and include only those amounts paid or accrued under the Production Participation Plan that relate to current period oil and natural gas operations. The increase in expense primarily reflects changes to future cash flows estimates due a higher price environment and acquisitions during 2004. 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 natural gas prices, discount rates and overall market conditions.

Interest Expense. The components of our interest expense were as follows:

	Year Ended December 31,	
	2004	**2003**
7.25% Senior Subordinated Notes due 2012	$ 5,957	$ —
Credit Agreement	5,893	6,643
Alliant Energy Corporation	150	1,224
Accretion of tax sharing liability	2,390	220
Amortization of debt issue costs and debt discount	1,666	1,090
Capitalized interest	(200)	—
Total interest expense	$ 15,856	$ 9,177

The increase in interest expense was primarily due to the May 2004 issuance of $150.0 million of 7.25% Senior Subordinated Notes due 2012. In August of 2004, $75.0 million of the face amount of the notes was swapped to a floating rate. The effect of the swap in 2004 was to lower our overall effective interest rate on this debt from 7.25% to approximately 6.2%. At December 31, 2004, the floating rate component was set at 4.65% through May 1, 2005, yielding a weighted average effective interest rate of 5.95% on the $150.0 million Senior Subordinated Notes

Interest expense on our credit agreement in 2004 was $0.8 million less than 2003. This was primarily the result of average outstanding borrowings in 2004 being $21.0 million lower than 2003. The effective cash interest rate paid in each year on the credit agreement was approximately 3.6%.

The decrease in interest expense related to Alliant Energy Corporation, our former parent company, was due to the March 31, 2003 conversion of $80.9 million of intercompany debt into our equity. The accretion of our tax sharing liability is related to a step-up in tax basis effected immediately prior to our initial public offering in November 2003. The increase was due to a full year of accretion expense in 2004. The increase in debt issue and debt discount amortization was due to the amortization of additional fees in 2004 to refinance our credit agreement and issue $150.0 million in 7.25% Senior Subordinated Notes due 2012.

Income Tax Expense. Income tax expense totaled $44.0 million for 2004 and $13.9 million for 2003, resulting in effective income tax rates of 38.6% for both years. The current portion of income tax expense was $3.9 million in 2004 compared to $2.4 million in 2003. These amounts are 8.8% and 17.1% of the total income tax expense for the respective periods. Prior to our initial public offering in November 2003, we were included in the consolidated federal income tax return of Alliant Energy, but for financial reporting purposes, we calculated our income tax expense on a separate return basis at Alliant Energy's effective income tax rate. Immediately prior to our initial public offering, Alliant Energy effected a step-up in the tax basis of Whiting Oil and Gas Corporation's assets, which had the result of increasing our future tax deductions. These additional deductions, combined with an increase in intangible drilling costs, allowed us to lower the percentage of taxes paid currently, even with the significant increase in oil and natural gas prices between years.

Cumulative Change in Accounting Principle. Effective January 1, 2003, we adopted the provisions of Statement of Financial Accounting Standards ("SFAS") No. 143, *Accounting for Asset Retirement Obligations*. This statement generally applies to legal obligations associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to plug and abandonment liabilities associated with our net working interest in oil and natural gas properties. The additional carrying amount is depleted over the estimated useful lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and the discount is accreted at the end of each accounting period. Upon adoption of SFAS No. 143, we recorded an increase to our discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

Net Income. Net income increased from $18.3 million for 2003 to $70.0 million for 2004. The primary reasons for this increase included 30% higher crude oil and natural gas prices net of hedging from 2003 to 2004, a 27% increase in equivalent volumes sold, the impact of the cumulative effect of adoption of SFAS No. 143 in 2003, the impact of property and marketable security sales in 2004, which were partially offset by higher lease operating expense, general and administrative, DD&A, interest and exploration and impairment costs in 2004 resulting from our continued growth.

Liquidity and Capital Resources

Overview. We entered 2005 with $1.7 million of cash and cash equivalents. During 2005, we generated $330.4 million from operating activities and $805.2 million from financing activities. We used these sources of cash primarily to finance drilling expenditures and acquisition capital expenditures of $1,126.9 million. At December 31, 2005, our debt to total capitalization ratio was 46.7%, we had $10.4 million of cash on hand and $997.9 million of stockholders' equity.

We continually evaluate our capital needs and compare them to our capital resources. Our 2006 budgeted capital expenditures for the further development of our property base are $360.0 million, an increase from the $223.6 million spent on capitalized development during 2005. Our 2005 development spending was a 182% increase from the $79.4 million spent on capitalized development costs during 2004. We also spent $930.7 million on acquisitions in 2005, funded primarily by our senior subordinated notes and common stock offerings as well as additional borrowings under Whiting Oil and Gas Corporation's credit agreement. Although we have no specific budget for property acquisitions in 2006, we will continue to seek property acquisition opportunities that complement our existing core property base. We expect to fund our 2006 development expenditures from internally generated cash flow and cash on hand. We believe that should attractive acquisition opportunities arise or development expenditures exceed $360.0 million, we are able to finance additional capital expenditures with cash on hand, operating cash flow, borrowings under our credit agreement, issuances of additional equity or agreements with industry partners. Our level of capital 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.

Credit Agreement. Whiting Oil and Gas Corporation has a $1.2 billion credit agreement with a syndicate of banks that, as of December 31, 2005, had a borrowing base of $787.5 million. The borrowing base under the credit agreement is determined by the discretion of the lenders based on the collateral value of our proved reserves 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, 2005, the outstanding principal balance under the credit agreement was $260.0 million.

The credit agreement provides for interest only payments until August 31, 2010, when the entire amount borrowed is due. We may, throughout the five-year term of the credit agreement, borrow, repay and re-borrow up to the borrowing base in effect from time to time. The lenders under the credit agreement have also committed to issue letters of credit for the account of Whiting Oil and Gas Corporation or other designated subsidiaries of ours from time to time in an aggregate amount not to exceed $50.0 million. As of December 31, 2005, letters of credit totaling $0.3 million were outstanding under the credit agreement.

Interest accrues, at our 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, 2005, the effective weighted average interest rate on the entire outstanding principal balance under the credit agreement was 5.3%.

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 (as defined in the credit agreement) ratio 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 Corporation and Equity Oil Company to make any dividends, distributions or other payments to us. 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, 2005. The credit agreement is secured by a first lien on all of Whiting Oil and Gas Corporation's properties included in the borrowing base for the credit agreement. We and our wholly-owned subsidiary, Equity Oil Company, have guaranteed the obligations of Whiting Oil and Gas under the credit agreement. We have pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for our guarantee, and Equity Oil Company has mortgaged all of its properties included in the borrowing base for the credit agreement as security for its guarantee.

Senior Subordinated Notes. On October 4, 2005, we issued $250.0 million aggregate principal amount of our 7% Senior Subordinated Notes due 2014. We used the net proceeds of $244.5 million from this offering along with the net proceeds of $277.0 million from the common stock offering discussed below to pay the cash portion of the purchase price for the acquisition of the North Ward Estes and ancillary properties and to repay $100.0 million of debt under Whiting Oil and Gas Corporation's credit agreement that was incurred in connection with the acquisition of the Postle properties. The 7% Senior Subordinated Notes due 2014 were issued at par.

On April 19, 2005, we issued $220.0 million aggregate principal amount of our 7.25% Senior Subordinated Notes due 2013. The 7.25% Senior Subordinated Notes due 2013 were issued at 98.507% of par and the associated discount is being amortized to interest expense over the term of the notes.

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

The notes are unsecured obligations of ours and are subordinated to all of our senior debt. The indentures governing the notes contain restrictive covenants that may limit our and our subsidiaries' 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 limit the discretion of our management in operating our business. In addition, Whiting Oil and Gas Corporation's credit agreement restricts the ability of our subsidiaries to make certain payments, including principal on the notes, to us. We were in compliance with these covenants as of December 31, 2005. Three of our 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.

Common Stock Offering. On October 4, 2005, we completed a public offering of 6,612,500 shares of our common stock. The offering was priced at $43.60 per share to the public. The number of shares includes the sale of 862,500 shares pursuant to the exercise of the underwriters' over-allotment option. We used the net proceeds from the offering of $277.0 million along with the net proceeds from the 7% Senior Subordinated Notes due 2014 of $244.5 million to pay the cash portion of the purchase price for the acquisition of the North Ward Estes and ancillary properties and to repay $100.0 million of debt outstanding under Whiting Oil and Gas Corporation's credit agreement that was incurred in connection with the acquisition of the Postle properties.

Alliant Energy Promissory Note. In conjunction with our initial public offering in November 2003, we issued a promissory note payable to Alliant Energy Corporation, our former parent company, in the aggregate principal amount of $3.0 million. We paid all principal and interest on the promissory note on November 25, 2005.

Tax Separation and Indemnification Agreement with Alliant Energy. In connection with our initial public offering in November 2003, we entered into a tax separation and indemnification agreement with Alliant Energy. Pursuant to this agreement, we and Alliant Energy made a tax election with the effect that the tax basis of the assets of Whiting Oil and Gas Corporation and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. We have adjusted deferred taxes on our balance sheet to reflect the new tax bases of our assets. These additional 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 to Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax bases for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing our actual taxes to the taxes that would have been owed by us had the increase in bases not occurred. 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. The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders' equity. During 2005, we made a payment of $5.1 million under this agreement. Our estimate of payments to be made under this agreement of $4.3 million in 2006 is reflected as a current liability at December 31, 2005.

Contractual Obligations and Commitments

Schedule of Contractual Obligations. The following table summarizes our material obligations and commitments as of December 31, 2005 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include asset retirement obligations or Production Participation Plan liabilities since we cannot determine with accuracy the timing of future payments. This table also does not include cash interest expense under our credit agreement since this is a floating rate instrument and we cannot determine with accuracy the timing of future loan advances, repayments or interest rates.

	Payments due by period				
Contractual Obligations	Total	Less than 1 year	2-3 years	4-5 years	More than 5 years
Long-term debt (a)	$ 875,098	$ —	$ —	$260,000	$615,098
Cash interest expense on notes (b)	326,663	43,982	87,964	87,964	106,753
Purchase obligations (c)	77,499	12,989	28,744	19,117	16,649
Drilling rig contracts (d)	26,444	18,195	8,249	—	—
Derivative contract liability fair value (e)	56,386	34,569	21,817	—	—
Operating leases (f)	7,557	1,701	3,163	2,693	—
Tax separation and indemnification agreement with Alliant Energy (g)	28,830	4,254	7,056	5,734	11,786
Total	$1,398,477	$ 115,690	$156,993	$375,508	$750,286

(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 6.8% until the due date of the instrument.

(c) In July 2005, we entered into a 9.5 year take-or-pay supply agreement, 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 on its Postle field in Texas County, Oklahoma. Under the terms of the agreement, we are obligated to purchase a minimum daily volume of CO_2 or else pay for any deficiencies at the price in effect when the minimum delivery was to have occurred. As calculated on an annual basis, Whiting's failure to purchase the minimum CO_2 volumes requires us to pay the supplier for any deficiency. The CO_2 volumes planned for use in the Postle field enhanced recovery projects currently exceed the minimum daily volumes provided in this take-or-pay supply agreement. Therefore, we expect to avoid any payments for deficiencies.

(d) During 2005, we entered into three separate agreements for three rigs drilling in the U.S. Rocky Mountain region. These contracts each have a term of three years, and early termination of these contracts at December 31, 2005 would have required maximum penalties of $14.1 million. No other drilling rigs working for us are currently under long-term contracts or contracts which cannot be terminated at the end of the well that is currently being drilled. Due to their short-term nature and the 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.

(e) We have entered into derivative contracts, primarily costless collars, to hedge its exposure to crude oil and natural gas price fluctuations. As of December 31, 2005, the forward price curves for oil and natural gas generally exceeded the price curves that were in effect when these contracts were entered into, resulting in a derivative fair value current liability of $34.6 million and long-term liability of $21.8 million. 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. See "Critical Accounting Policies and Estimates-*Hedging*" and Item 7A. Quantitative and Qualitative Disclosure About Market Risk for additional information regarding our derivative obligations.

(f) We lease 87,000 square feet of administrative office space under an operating lease arrangement through October 31, 2010 and an additional 23,000 square feet of office space in Midland, Texas starting from October 4, 2005.

(g) Amounts shown are estimates based on estimated future income tax benefits from the increase in tax bases described under "Tax Separation and Indemnification Agreement with Alliant Energy" above.

Price-Sharing Arrangements. As part of a 2002 purchase transaction, we agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2006 increased to 50% of the actual price received in excess of $20.56 per barrel. As of December 31, 2005, approximately 39,200 net barrels of crude oil per month (5% of December 2005 net crude oil production) are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. During the years 2005, 2004 and 2003, we paid $7.6 million, $4.8 million and $2.3 million, respectively, under this agreement. As of December 31, 2005, we have accrued an additional $0.7 million as currently payable.

New Accounting Policies

In December 2004, the FASB issued a revision of SFAS No. 123, *Accounting for Stock-Based Compensation* ("SFAS 123R"). SFAS 123R supersedes Accounting Principles Board Opinion No. 25, *Accounting for Stock Issued to Employees*, and its related implementation guidance. SFAS 123R establishes standards for the accounting for transactions in which an entity incurs liabilities in exchange for goods or services that are based on the fair value of the entity's equity instruments or that may be settled by the issuance of those equity instruments. SFAS 123R does not change the accounting guidance for share-based payment transactions with parties other than employees provided in SFAS No. 123 as originally issued and EITF Issue No. 96-18, "Accounting for Equity Instruments That Are Issued to Other Than Employees for Acquiring, or in Conjunction with Selling, Goods or Services." SFAS 123R requires all share-based payments to employees, including restricted stock grants, to be recognized in the financial statements based on their fair values, beginning with the first interim or annual period of the registrant's first fiscal year beginning on or after June 15, 2005, with early adoption encouraged. The adoption of SFAS 123R is not expected to have a material impact on our consolidated financial position, results of operations or cash flows.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"). FIN 47 clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the company. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. FIN 47 is intended to provide more information about long-lived assets and future cash outflows for these obligations and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The adoption of FIN 47 is not expected to have a material impact on our consolidated financial position, results of operations or cash flows.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operation 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.

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

Hedging. We periodically enter into commodity derivative contracts to manage our exposure to oil and natural gas price volatility. We primarily utilize costless collars, which are generally placed with major financial institutions. The oil and natural gas reference prices of these commodity derivatives contracts are based upon crude oil and natural gas futures, which have a high degree of historical correlation with actual prices we receive. Under SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activity,* 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 gain or loss on the derivative is deferred in accumulated other comprehensive income (loss) to the extent the hedge is effective and is reclassified to the "Loss on oil and 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 internally using established index prices and other sources. 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.

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 hedges did not qualify for cash flow hedge treatment, then our consolidated income statements could include large non-cash fluctuations, particularly in volatile pricing environments, as our contracts are marked to their period end market values.

Successful Efforts Accounting. We account for our oil and natural 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 natural gas production costs. Except for one small property in Canada, all of our properties are located within the continental United States and the Gulf of Mexico.

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 natural gas properties, and our long-term Production Participation Plan liability. Proved oil and natural 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 Ryder Scott Company, Cawley, Gillespie & Associates, Inc., R.A. Lenser & Associates, Inc., and Netherland, Sewell & Associates, Inc., each independent petroleum engineers, and our engineering staff. The independent petroleum engineers evaluated 100% of the standardized measure of discounted future net cash flows of our proved reserves as of December 31, 2005. 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 natural 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 and our Production Participation Plan liability in the same period that changes to the 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 incorporate assumptions regarding future development and abandonment costs as well as our level of capital spending. 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 market 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 natural gas properties whenever management judges that events and circumstances indicate that the recorded carrying value of properties may not be recoverable. We provide for impairments on undeveloped property when we determine that the property will not be developed or a permanent impairment in value has occurred. 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 net 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.

Production Participation Plan. We have a Production Participation Plan which benefits all eligible employees. Each year, a deemed economic interest in all oil and natural 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 on our consolidated balance sheet. 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 above under "Revenue Recognition". The vested long-term obligation related to the Production Participation Plan is the "Production Participation Plan Liability" line item on the consolidated balance sheet. This liability is derived primarily from reserve report estimates discounted at 15%, 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, 2005 would have decreased net income before taxes by $2.9 million in 2005.

Income Taxes. 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 under accounting standards, the tax asset would be reduced by a valuation allowance. We consider future taxable income in making such assessments. Numerous judgments and assumptions are inherent in the determination of future taxable income, including factors such as future operating conditions (particularly as related to prevailing oil and natural gas prices).

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.

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 two years consisted of oil and natural gas properties or companies with oil and natural gas interests. The consideration we have paid to acquire these properties or companies was entirely allocated the fair value of the assets acquired and liabilities assumed at the time of acquisition. Consequently, there was no goodwill to be recognized from any of our business combinations.

Asset Retirement Obligation. Our asset retirement obligations (“ARO”) consist primarily of estimated costs of dismantlement, removal, site reclamation and similar activities associated with its oil and natural gas properties. SFAS No. 143 requires that the discounted fair value of a liability for an ARO 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 natural gas asset. The recognition of an ARO requires that management make numerous estimates, assumptions and judgments 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.

Effects of Inflation and Pricing

We experienced increased costs during 2005, 2004 and 2003 due to increased demand for oil field products and services. The oil and natural gas industry is very cyclical and the demand for goods and services of oil field companies, suppliers and others associated with the industry put extreme pressure on the economic stability and pricing structure within the industry. Typically, as prices for oil and natural gas increase, so do all associated costs. 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 natural 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 natural gas could result in increases in the costs of materials, services and personnel.

Item 7A. Quantitative and Qualitative Disclosure About Market Risk

Commodity Price Risk

The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. 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 natural 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 2005 production, our income before income taxes for 2005 would have moved up or down approximately $2.8 million for every $0.10 change in natural gas prices and approximately $6.6 million for each $1.00 change in crude oil prices.

We periodically enter into derivative contracts to manage our exposure to oil and natural gas price volatility. Our derivative contracts have traditionally been costless collars, although we evaluate other forms of derivative instruments as well. Our derivative contracts have historically qualified for cash flow hedge accounting under SFAS No. 133. This accounting treatment allows the aggregate change in fair market value to be recorded as other comprehensive income. Recognition in the consolidated income statement occurs in the period of contract settlement. We also seek to diversify our hedge position with various counterparties where we have clear indications of their current financial strength.

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Our outstanding hedges as of February 15, 2006 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)	NYMEX Floor/Ceiling
Natural Gas	01/2006 to 03/2006	750,000	$ 5.90/$10.30
Natural Gas	01/2006 to 03/2006	450,000	$ 6.00/$16.00
Natural Gas	01/2006 to 03/2006	300,000	$ 6.00/$17.00
Natural Gas	04/2006 to 06/2006	600,000	$ 6.00/$10.10
Natural Gas	04/2006 to 06/2006	1,000,000	$ 6.00/$10.12
Natural Gas	07/2006 to 09/2006	600,000	$ 6.00/$10.28
Natural Gas	07/2006 to 09/2006	1,000,000	$ 6.00/$10.38
Natural Gas	10/2006 to 12/2006	600,000	$ 6.00/$12.28
Natural Gas	10/2006 to 12/2006	1,000,000	$ 6.00/$12.18
Natural Gas	01/2007 to 03/2007	600,000	$ 6.00/$15.20
Natural Gas	01/2007 to 03/2007	1,000,000	$ 6.00/$15.52
Crude Oil	01/2006 to 03/2006	250,000	$40.00/$51.50
Crude Oil	01/2006 to 03/2006	110,000	$50.00/$76.55
Crude Oil	01/2006 to 03/2006	50,000	$50.00/$82.25
Crude Oil	04/2006 to 06/2006	125,000	$45.00/$82.80
Crude Oil	04/2060 to 06/2006	215,000	$50.00/$73.80
Crude Oil	04/2006 to 06/2006	110,000	$50.00/$76.20
Crude Oil	07/2006 to 09/2006	125,000	$45.00/$81.90
Crude Oil	07/2006 to 09/2006	215,000	$50.00/$72.90
Crude Oil	07/2006 to 09/2006	110,000	$50.00/$75.25
Crude Oil	10/2006 to 12/2006	125,000	$45.00/$81.10
Crude Oil	10/2006 to 12/2006	215,000	$50.00/$72.05
Crude Oil	10/2006 to 12/2006	110,000	$50.00/$74.30
Crude Oil	01/2007 to 03/2007	125,000	$45.00/$81.00
Crude Oil	01/2007 to 03/2007	215,000	$50.00/$70.90
Crude Oil	01/2007 to 03/2007	110,000	$50.00/$73.15
Crude Oil	04/2007 to 06/2007	110,000	$50.00/$72.00
Crude Oil	04/2007 to 06/2007	300,000	$50.00/$78.50
Crude Oil	07/2007 to 09/2007	110,000	$50.00/$70.90
Crude Oil	07/2007 to 09/2007	300,000	$50.00/$77.55
Crude Oil	10/2007 to 12/2007	110,000	$49.00/$71.50
Crude Oil	10/2007 to 12/2007	300,000	$50.00/$76.50
Crude Oil	01/2008 to 03/2008	110,000	$49.00/$70.65
Crude Oil	04/2008 to 06/2008	110,000	$48.00/$71.60
Crude Oil	07/2008 to 09/2008	110,000	$48.00/$70.85
Crude Oil	10/2008 to 12/2008	110,000	$48.00/$70.20

The collared hedges shown above have the effect of providing a protective floor while allowing us to share in upward pricing movements. Consequently, while these hedges are designed to decrease our exposure to price decreases, they also have the effect of limiting the benefit of price increases beyond the ceiling. For the 2006 natural gas contracts listed above, a hypothetical $0.10 change in the NYMEX price above the ceiling price or below the floor price applied to the notional amounts would cause a change in the gain (loss) on hedging activities in 2006 of $1.9 million. For the 2006 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 2006 of $1.8 million.

We have also entered into fixed price marketing contracts directly with end users for a portion of the natural gas we produce in Michigan. All of those contracts have built-in pricing escalators of 4% per year. Our outstanding fixed price marketing contracts at February 15, 2006 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	2006 Price Per MMBtu
Natural Gas	01/2002 to 12/2011	51,000	$ 4.57
Natural Gas	01/2002 to 12/2012	60,000	$ 4.05

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. At December 31, 2005, our outstanding principal balance under our credit agreement was $260.0 million and the weighted average interest rate on the entire outstanding principal balance was fixed at 5.3% through March 31, 2006. At December 31, 2005, the carrying amount approximated fair market value. Assuming a constant debt level of $260.0 million, the cash flow impact for 2005 resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $2.0 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 under the provisions of Statement of Financial Accounting Standards No. 133, 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 at December 31, 2005 was 4.69%. As of December 31, 2005, we have recorded a long term liability of $1.1 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding decrease in the carrying value of the Senior Subordinated Notes.

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, 2005 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, 2005, our internal control over financial reporting was effective based on those criteria.

Deloitte & Touche LLP, our independent registered public accounting firm, has issued an attestation report on management's assessment of our internal control over financial reporting. That attestation report is set forth immediately prior to the report of Deloitte & Touche LLP on the financial statements included herein.

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of
Whiting Petroleum Corporation:

We have audited management's assessment, included in the accompanying Management's Annual Report on Internal Control Over Financial Reporting, that Whiting Petroleum Corporation and subsidiaries (the "Company") maintained effective internal control over financial reporting as of December 31, 2005, 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. Our responsibility is to express an opinion on management's assessment and an opinion on the effectiveness of 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, evaluating management's assessment, testing and evaluating the design and operating effectiveness of internal control, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinions.

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, management's assessment that the Company maintained effective internal control over financial reporting as of December 31, 2005, is fairly stated, in all material respects, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission. Also in our opinion, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2005, based on the criteria established in *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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, 2005 of the Company and our report dated February 23, 2006 expressed an unqualified opinion on those financial statements and financial statement schedule.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2006

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, 2005 and 2004, 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, 2005. Our audits also included the financial statement schedule listed in 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 these 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 referred to above present fairly, in all material respects, the financial position of Whiting Petroleum Corporation and subsidiaries as of December 31, 2005 and 2004, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2005, in conformity with accounting principles generally accepted in the United States of America. Also, in our opinion, such financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presents fairly, in all material respects, the information set forth therein.

As discussed in Note 1 to the consolidated financial statements, in 2003 the Company changed its method of accounting for asset retirement obligations to conform to Statement of Financial Accounting Standards No. 143.

We have also audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the effectiveness of the Company’s internal control over financial reporting as of December 31, 2005, based on criteria established in *Internal Control–Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission and our report dated February 23, 2006 expressed an unqualified opinion on management’s assessment of the effectiveness of the Company’s internal control over financial reporting and an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado
February 23, 2006

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2005	December 31, 2004
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 10,382	$ 1,660
Accounts receivable trade, net	101,066	63,489
Deferred income taxes	15,121	2,368
Prepaid expenses and other	7,905	7,603
Total current assets	134,474	75,120
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	2,353,372	1,225,676
Unproved properties	21,671	6,038
Other property and equipment	26,235	7,517
Total property and equipment	2,401,278	1,239,231
Less accumulated depreciation, depletion and amortization	(338,420)	(244,246)
Total property and equipment—net	2,062,858	994,985
DEBT ISSUANCE COSTS	23,660	11,823
OTHER LONG-TERM ASSETS	14,204	10,278
TOTAL	$2,235,196	$1,092,206

(Continued)

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS
(In thousands, except share data)

	December 31, 2005	December 31, 2004
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 68,033	$ 19,815
Accrued interest	11,894	2,050
Oil and gas sales payable	21,154	4,987
Accrued employee compensation and benefits	15,351	7,808
Production taxes payable	13,259	8,254
Current portion of tax sharing liability	4,254	4,214
Current portion of long-term debt	—	3,167
Current portion of derivative liability	34,569	1,670
Income taxes payable and other liabilities	—	129
Total current liabilities	168,514	52,094
NON-CURRENT LIABILITIES		
Asset retirement obligations	32,246	31,639
Production Participation Plan liability	19,287	9,579
Tax sharing liability	24,576	26,966
Long-term debt	875,098	325,261
Deferred income taxes	91,577	34,281
Long-term derivative liability	21,817	—
Other long-term liabilities	4,219	—
Total non-current liabilities	1,068,820	427,726
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS' EQUITY:		
Common stock, $.001 par value; 75,000,000 shares authorized, 36,841,823 and 29,717,808 shares issued and outstanding as of December 31, 2005 and 2004, respectively	37	30
Additional paid-in capital	753,093	455,635
Accumulated other comprehensive loss	(34,620)	(1,025)
Deferred compensation	(2,031)	(1,715)
Retained earnings	281,383	159,461
Total stockholders' equity	997,862	612,386
TOTAL	$2,235,196	$1,092,206

(Concluded)

See notes to consolidated financial statements.

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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

	Year Ended December 31, 2005	2004	2003
REVENUES AND OTHER INCOME:			
Oil and gas sales	$573,246	$281,057	$175,731
Loss on oil and gas hedging activities	(33,377)	(4,875)	(8,680)
Gain on sale of marketable securities	—	4,835	—
Gain on sale of oil and gas properties	—	1,000	—
Interest income and other	579	123	330
Total revenues and other income	540,448	282,140	167,381
COSTS AND EXPENSES:			
Lease operating	111,560	54,212	43,213
Production taxes	36,092	16,793	10,691
Depreciation, depletion and amortization	97,639	54,010	41,256
Exploration and impairment	16,699	6,329	3,186
General and administrative	30,607	19,224	12,990
Change in Production Participation Plan liability	9,708	1,711	(185)
Phantom equity plan	—	—	10,914
Interest expense	42,045	15,856	9,177
Total costs and expenses	344,350	168,135	131,242
INCOME BEFORE INCOME TAXES AND CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	196,098	114,005	36,139
INCOME TAX EXPENSE:			
Current	8,514	3,882	2,389
Deferred	65,662	40,077	11,560
Total income tax expense	74,176	43,959	13,949
INCOME BEFORE CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	121,922	70,046	22,190
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE, NET OF TAX	—	—	(3,905)
NET INCOME	$121,922	$ 70,046	$ 18,285
Income per share before cumulative change in accounting principle, basic	$ 3.89	$ 3.38	$ 1.18
Cumulative change in accounting principle	—	—	(0.20)
NET INCOME PER COMMON SHARE, BASIC	$ 3.89	$ 3.38	$ 0.98
Income per share before cumulative change in accounting principle, diluted	$ 3.88	$ 3.38	$ 1.18
Cumulative change in accounting principle	—	—	(0.20)
NET INCOME PER COMMON SHARE, DILUTED	$ 3.88	$ 3.38	$ 0.98
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	31,356	20,735	18,750
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	31,449	20,768	18,750

See notes to consolidated financial statements.

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

	Common Stock		Additional Paid-in Capital	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Retained Earnings	Total Stockholders' Equity	Comprehensive Income
	Shares	Amount						
BALANCES-January 1, 2003	18,750	$ 19	$ 53,219	$ (1,550)	$ —	$ 71,130	$ 122,818	
Net income	—	—	—	—	—	18,285	18,285	18,285
Unrealized net gain on marketable equity securities for sale	—	—	—	664	—	—	664	664
Change in derivative instrument fair value	—	—	—	663	—	—	663	663
Conversion of Alliant note payable to equity	—	—	80,931	—	—	—	80,931	—
Issuance of note payable	—	—	(3,000)	—	—	—	(3,000)	—
Phantom equity plan contribution	—	—	10,666	—	—	—	10,666	—
Tax basis step-up	—	—	28,551	—	—	—	28,551	—
BALANCES—December 31, 2003	18,750	19	170,367	(223)	—	89,415	259,578	19,612
Net income	—	—	—	—	—	70,046	70,046	70,046
Change in fair value of marketable securities for sale	—	—	—	3,741	—	—	3,741	3,741
Realized gain on marketable securities for sale	—	—	—	(4,835)	—	—	(4,835)	(4,835)
Change in derivative instrument fair value	—	—	—	(2,701)	—	—	(2,701)	(2,701)
Realized loss on settled derivative contracts, net of related taxes	—	—	—	2,993	—	—	2,993	2,993
Issuance of stock – Equity Oil Company merger	2,237	2	43,296	—	—	—	43,298	—
Issuance of stock – secondary offering	8,625	9	239,677	—	—	—	239,686	—
Restricted stock issued	113	—	2,459	—	(2,459)	—	—	—
Restricted stock forfeited	(7)	—	(164)	—	164	—	—	—
Amortization of deferred compensation	—	—	—	—	580	—	580	—
BALANCES—December 31, 2004	29,718	30	455,635	(1,025)	(1,715)	159,461	612,386	69,244
Net income	—	—	—	—	—	121,922	121,922	121,922
Change in derivative instrument fair value	—	—	—	(54,089)	—	—	(54,089)	(54,089)
Realized loss on settled derivative contracts, net of related taxes	—	—	—	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)	—
Net tax effect arising from restricted stock activity	—	—	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

See notes to consolidated financial statements.

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In thousands)

	Year Ended December 31, 2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 121,922	$ 70,046	$ 18,285
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	97,639	54,010	41,256
Deferred income taxes	65,662	40,077	11,560
Amortization of debt issuance costs and debt discount	4,076	1,466	1,091
Accretion of tax sharing agreement	2,725	2,390	220
Amortization of deferred compensation	2,861	580	—
Gain on sale of marketable securities	—	(4,835)	—
Gain on sale of oil and gas properties	—	(1,000)	—
Impairment of oil and gas properties	2,034	2,152	—
Change in Production Participation Plan liability	9,708	1,711	(185)
Phantom equity plan	—	—	6,510
Cumulative change in accounting principle	—	—	3,905
Other non-current	372	(3,287)	(147)
Changes in current assets and liabilities:			
Accounts receivable trade	(35,012)	(34,633)	(307)
Prepaid expenses and other	(302)	(4,919)	4,176
Accounts payable	20,318	(650)	2,019
Accrued interest	9,844	628	925
Other liabilities	28,586	10,380	2,621
Net cash provided by operating activities	330,434	134,116	91,929
CASH FLOWS FROM INVESTING ACTIVITIES:			
Cash acquisition capital expenditures	(900,332)	(451,231)	(2,786)
Drilling capital expenditures	(196,163)	(79,376)	(40,336)
Proceeds from sale of marketable securities	—	5,420	—
Proceeds from sale of oil and gas properties	—	1,000	—
Equity Oil Company cash paid in excess of cash received	—	(256)	—
Acquisition of partnership interests, net of cash received	(30,433)	—	(4,453)
Net cash used in investing activities	(1,126,928)	(524,443)	(47,575)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Advances from (repayments to) Alliant	(8,242)	—	4,616
Issuance of common stock	277,117	239,686	—
Issuance of 7.25% Senior Subordinated Notes due 2012	—	148,890	—
Issuance of 7.25% Senior Subordinated Notes due 2013	216,715	—	—
Issuance of 7% Senior Subordinated Notes due 2014	250,000	—	—
Issuance of long-term debt under credit agreement	395,000	445,800	—
Payments on long-term debt under credit agreement	(310,000)	(484,800)	—
Debt issuance costs	(15,370)	(11,174)	(218)
Restricted stock used for tax withholdings	(241)	—	—
Net tax effect arising from restricted stock activity	237	—	—
Net cash provided by financing activities	805,216	338,402	4,398
NET CHANGE IN CASH AND CASH EQUIVALENTS	8,722	(51,925)	48,752
CASH AND CASH EQUIVALENTS:			
Beginning of period	1,660	53,585	4,833
End of period	$ 10,382	$ 1,660	$ 53,585
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid (refunded) for income taxes	$ 10,620	$ 4,479	$ (1,425)
Cash paid for interest	$ 26,113	$ 11,222	$ 6,464
NONCASH INVESTING ACTIVITIES:			
Changes in working capital related to drilling capital expenditures	$ 27,432	$ 4,412	$ 4,436
NONCASH FINANCING ACTIVITIES:			
Assumption of debt – Equity Oil Company merger	$ —	$ 29,000	$ —
Issuance of common stock – Equity Oil Company merger	$ —	$ 43,298	$ —
Issuance of common stock – North Ward Estes acquisition	$ 17,175	$ —	$ —
Alliant debt converted to equity	$ —	$ —	$ 80,931

See notes to consolidated financial statements.

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS
(In thousands, except share and per share data)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations—Whiting Petroleum Corporation ("Whiting" or the "Company") is an independent oil and gas company that acquires, 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. Whiting is a Delaware corporation that prior to its initial public offering in November 2003 was a wholly owned indirect subsidiary of Alliant Energy Corporation ("Alliant Energy" or "Alliant"), a holding company whose primary businesses are utility companies. Just prior to the public offering of the Company's common stock by Alliant Energy, the Company in effect split its common stock, issuing approximately 18,330,000 shares for the 1 previously held by Alliant Energy. The 2003 periods presented have been adjusted to reflect the current capital structure.

Basis of Presentation of Consolidated Financial Statements—The consolidated financial statements include the accounts of Whiting and its 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 of 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 us 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 significant 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 natural gas reserves; (2) cash flow estimates used in impairment tests of long-lived assets; (3) depreciation, depletion and amortization; (4) dismantlement and future abandonment costs; (5) assigning fair value and allocating purchase price in connection with business combinations; (6) income taxes; (7) Production Participation Plan and other accrued liabilities; and (8) valuation of derivative instruments. Although management believes these estimates are reasonable, actual results could differ from these estimates.

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

Accounts Receivable Trade—The Company routinely assesses the recoverability of all material trade and other receivable to determine their collectibility. Many of Whiting's receivables are from joint interest owners on properties the Company operates. Thus, Whiting may have the ability to withhold future revenue disbursements to recover any non-payment of joint interest billings. Generally, the Company's crude oil and natural gas receivables are collected within two months and to date, the Company has had minimal bad debts.

At December 31, 2005 and 2004, the Company had recorded an allowance for doubtful accounts of $0.4 million and $0.3 million, respectively.

Fair Value of Financial Instruments—The Company's financial instruments, including 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 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 discussed in Long-Term Debt. The unhedged portion of the Company's Senior Subordinated Notes are recorded at cost and the fair value is disclosed in Long-Term Debt. The Company's derivative instruments are marked-to-market with changes in value being recorded in accumulated other comprehensive income (loss).

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 2005, sales to Teppco Crude Oil LLC accounted for 10% of the Company's total oil and natural gas production revenue. During 2004 and 2003, no single customer was responsible for generating 10% or more of the Company's total oil and natural gas sales.

Inventories—Materials and supplies inventories consist primarily of tubular goods and other lease and well equipment that the Company plans to utilize in its ongoing exploration and development activities and are carried 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 natural gas properties. Under this method of accounting, all property acquisition costs and development costs are capitalized when incurred and amortized 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 natural 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 natural gas properties is generally determined based on discounted future net cash flows.

Gains and losses are recognized on sales of entire interests in properties. Sales of partial interests are generally treated as recoveries of costs. Expenditures for maintenance, repairs and minor renewals necessary to maintain properties in operating condition are expensed as incurred. Major replacements and renewals are capitalized. Estimated dismantlement and abandonment costs for oil and natural gas properties are capitalized at their estimated net present value and amortized on a unit-of-production basis over the remaining life of the related proved developed reserves.

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 2005, 2004 and 2003, capitalized interest costs were not significant.

Unproved. Unproved properties consist of costs incurred to acquire unproved leases as well as costs to acquire unproved reserves. As unproved reserves are developed and proven, the associated costs are reclassified to proved properties and depleted on a unit-of-production basis. The Company evaluates unproved property costs for impairment based on time, drilling results, reservoir performance, seismic interpretation or future plans to develop acreage. 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 exploration and development costs.

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 that 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 are stated at cost and depreciated using the straight-line method over a period of four years. Maintenance and repair costs which do not extend the useful lives of the property and equipment are charged to expense as incurred. When other property and equipment is sold or retired, the related costs and accumulated depreciation are removed from the accounts. Also included in Other Property and Equipment are material and supplies inventories.

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.

Reimbursed Overhead—The Company provides various administrative services to its joint interest owners of certain oil and natural gas properties for which the Company receives overhead reimbursements. Amounts earned are included as a reduction to general and administrative expense and totaled $12.0 million, $6.8 million and $5.6 million for the years ended December 31, 2005, 2004 and 2003, respectively.

Abandonment Liability—Effective January 1, 2003, the Company adopted the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligations*. This Statement generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize the fair value of asset retirement obligations in the financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to the Company, asset retirement obligations primarily relate to the abandonment of oil and natural gas producing facilities. The discounted liability is accreted at the end of each accounting period through charges to depreciation, depletion and amortization expense. If the obligation is settled for other than the carrying amount, then a gain or loss is recognized on settlement.

Revenue Recognition—The Company recognizes revenues from the production of oil and natural gas when production is delivered and title transfers. Revenues from the production of natural 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). Natural gas imbalance receivables or payables are generally valued at the lower of current market value or the price in effect at the time of production. As of December 31, 2005, 2004 and 2003, the Company was in an (over) under produced imbalance position of approximately (162,000 Mcf), 339,000 Mcf and 206,000 Mcf, respectively.

Derivative Instruments— The Company enters into derivative contracts, primarily costless collars, to hedge future natural gas and crude oil production in order to mitigate the risk of market price fluctuations. The Company also enters into derivative contracts to mitigate the risk of interest rate fluctuations. The Company does not enter into derivative instruments for speculative trading purposes.

All derivatives are recognized on the balance sheet and measured at fair value. Realized and unrealized gains and losses on derivatives that are not designated as hedges, as well as the ineffective portion of hedge derivatives, if any, are recorded as a derivative fair value gain or loss in the consolidated statements of income. Unrealized gains and losses on effective cash flow hedge derivatives are recorded as a component of accumulated other comprehensive income (loss). When the hedged transaction occurs, the realized gain or loss on the hedge derivative is transferred from accumulated other comprehensive income (loss) to earnings. Realized gains and losses on commodity hedge derivatives are recognized as "gain (loss) on oil and gas hedging activities", and realized gains and losses on interest hedge derivatives are recorded as adjustments to interest expense. Derivative settlements are included in cash flows from operating activities.

The Company has formally documented all relationships between hedging instruments and hedged items, as well 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. 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. If, during the derivative's term, the Company determines the hedge is no longer highly effective, hedge accounting is prospectively discontinued and any remaining unrealized gains or losses on the effective portion of the derivative are reclassified to earnings when the underlying transaction occurs. If it is determined that the designated hedge transaction is not likely to occur, any unrealized gains or losses are recognized immediately in the consolidated statements of income as a derivative fair value gain or loss.

Physical delivery contracts that are not expected to be net cash settled are deemed to be normal sales and therefore are not accounted for as derivatives.

At December 31, 2005, accumulated other comprehensive loss consisted of $56.4 million ($34.6 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, 2004, accumulated other comprehensive income consisted of $1.7 million ($1.0 million after tax) of unrealized losses on the Company's open commodity hedge derivatives. Included as a portion of accumulated other comprehensive loss as of December 31, 2003, was $2.1 million ($1.3 million after tax) of unrealized losses on the Company's open commodity hedges.

For the years ended December 31, 2005, 2004 and 2003, Whiting recognized realized losses of $33.4 million, $4.9 million and $8.7 million, respectively, on commodity derivative settlements.

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

Marketable Securities—Investments in marketable securities are classified as held-to-maturity, trading securities or available-for-sale. Trading and available-for-sale securities are recorded at estimated market value. Realized gains or losses for both classes of equity investments are determined on a specific identification basis and are included in income. Unrealized gains or losses of available-for-sale securities are excluded from earnings and reported in other comprehensive income.

As of December 31, 2003, the Company had equity investments in publicly traded securities classified as available-for-sale (included in other long term-assets) with an original cost to the Company of $0.6 million and a fair value of $2.4 million. During 2004, the Company sold all of its holdings for $5.4 million, realizing a gain on sale of $4.8 million. As of December 31, 2003, the Company recorded an unrealized holding gain of $1.8 million, correspondingly $1.1 million was recorded as a component of accumulated other comprehensive loss and $0.7 million was recorded as a decrease to the deferred tax asset.

Income Taxes— Deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases and operating loss and tax credit carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that includes the enactment date. Prior to the Company's initial public offering in November 2003, the Company was included in the consolidated federal income tax return of Alliant Energy but was treated as a separate entity for income tax and financial reporting purposes.

Stock-Based Compensation—The Company accounts for stock based compensation using the intrinsic value method. Compensation related to restricted stock grants with time vesting conditions is based on the fair value of the award at the grant date and recognized over the vesting period. No adjustments to the Company's net income or earnings per share are required pursuant to SFAS No. 123, *Accounting for Stock-Based Compensation*.

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

Industry Segment and Geographic Information— In accordance with SFAS No. 131, *Disclosures about Segments of an Enterprise and Related Information*, the Company evaluated how it is organized and managed, and has identified only one operating segment, which is the exploration and production of oil, natural gas and natural gas liquids. The Company considers its gathering, processing and marketing functions as ancillary to its oil and natural gas producing activities. Substantially 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.

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. In addition, the Company determined during 2005 that accrued capital expenditures should be reported as supplemental non-cash investing activities and should not be included in the Company's statement of cash flows. The Company also concluded that changes in materials and supplies inventories should be reported as an investing activity in the Company's statement of cash flows and not as an operating activity. During 2005, the Company therefore changed the classification of certain amounts in its statement of cash flows from those amounts previously reported. For the years ended December 31, 2004 and 2003, this change had the effect of reducing drilling capital expenditures by $1.4 million and $4.4 million, respectively, and decreasing net cash provided by operating activities by the same amount with no impact on net income or stockholders' equity.

New Accounting Pronouncements—In December 2004, the FASB issued Statement of Financial Accounting Standards No. 123R, *Share-Based Payment* ("SFAS 123R"), which is a revision of SFAS No. 123, *Accounting for Stock-Based Compensation*. SFAS 123R, supersedes APB Opinion No. 25, *Accounting for Stock Issued to Employee*, and amends SFAS No. 95, *Statement of Cash Flows*. SFAS 123R requires all share-based payments to employees, including restricted stock grants, to be recognized in the financial statements based on their fair values, beginning with the first interim or annual period of the registrant's first fiscal year beginning on or after June 15, 2005, with early adoption encouraged. The pro forma disclosures previously permitted under SFAS No. 123 will no longer be an alternative to financial statement recognition. SFAS 123R also requires the tax benefits in excess of recognized compensation expense to be reported as a financing cash flow, rather than as an operating cash flow as currently required. The adoption of SFAS 123R is anticipated to have a minimal impact on the Company's consolidated financial position, results of operations and cash flows.

In March 2005, the FASB issued FASB Interpretation No. 47, *Accounting for Conditional Asset Retirement Obligations* ("FIN 47"). FIN 47 clarifies the definition and treatment of conditional asset retirement obligations as discussed in FASB Statement No. 143, *Accounting for Asset Retirement Obligations*. A conditional asset retirement obligation is defined as an asset retirement activity in which the timing and/or method of settlement are dependent on future events that may be outside the control of the company. FIN 47 states that a company must record a liability when incurred for conditional asset retirement obligations if the fair value of the obligation is reasonably estimable. FIN 47 is intended to provide more information about long-lived assets and future cash outflows for these obligations and more consistent recognition of these liabilities. FIN 47 is effective for fiscal years ending after December 15, 2005. The adoption of FIN 47 is not expected to have a material impact on the Company's consolidated financial position, results of operations or cash flows.

2. ACQUISITIONS

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 approximately 82.1 MMBOE as of the acquisition effective date of July 1, 2005, resulting in a cost of approximately $5.58 per BOE of estimated proved reserves. The average daily production from the properties was approximately 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, both of which closed on October 4, 2005.

Postle Field—On August 4, 2005, the Company acquired the operated interest in producing oil and natural gas fields located in the Oklahoma Panhandle. The purchase price was $343.0 million for estimated proved reserves of approximately 40.3 MMBOE as of the acquisition effective date of

July 1, 2005, resulting in a cost of approximately $8.52 per BOE of estimated proved reserves. The average daily production from the properties was approximately 4.2 MBOE/d as of the acquisition effective date. The Company funded the acquisition through borrowings under Whiting Oil and Gas' 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 approximately 2.9 MMBOE as of the acquisition effective date of January 1, 2005, resulting in a cost of approximately $10.52 per BOE of estimated proved reserves. 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 approximately 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. The average daily production from the properties was approximately 1.1 MBOE/d as of the acquisition effective date. The Company funded the acquisition through borrowings under Whiting Oil and Gas' 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 preliminary 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).

	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	—	17,176	—
Total	$ 343,000	$459,176	$ 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)	(4,164)	(2,495)
Total	$ 343,000	$459,176	$ 95,433

2004 Acquisitions

Permian Basin Properties—On September 23, 2004, the Company acquired interests in seventeen fields in the Permian Basin of West Texas and Southeast New Mexico, including interests in key fields such as Parkway field in Eddy County, New Mexico; Would Have and Signal Peak fields in Howard County, Texas; Keystone field in Winkler County, Texas; and the DEB field in Gaines County, Texas. The purchase price was $345.0 million in cash and was funded through borrowings under the Company's bank credit agreement. Based on the purchase price and estimated proved reserves of 41.9 MMBOE on the effective date of the acquisition, the Company acquired these properties for approximately $8.22 per BOE of proved reserves.

Equity Oil Company —The Company acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, the Company issued 2.2 million shares of its common stock to Equity's shareholders and repaid all of Equity's outstanding debt of $29.0 million under its credit facility. Equity's operations are focused primarily in California, Colorado, North Dakota and Wyoming. Based on the purchase price of $72.6 million and estimated proved reserves of 14.6 MMBOE on the effective date of the acquisition, the Company acquired these properties for approximately $4.98 per BOE of estimated proved reserves.

Other Cash Acquisitions of Properties

Colorado and Wyoming Properties—On August 13, 2004, the Company acquired interests in four producing oil and natural gas fields in Colorado and Wyoming. The purchase price was $44.2 million in cash and was funded under the Company's bank credit agreement. Based on the purchase price of $44.2 million and estimated proved reserves of 6.6 MMBOE on the effective date of the acquisition, the Company acquired these properties for approximately $6.66 per BOE of estimated proved reserves.

Louisiana and South Texas Properties—On August 16, 2004, the Company acquired interests in five fields in Louisiana and South Texas. The purchase price was $19.3 million in cash and was funded under the Company's bank credit agreement. Based on the purchase price of $19.3 million and estimated proved reserves of 2.0 MMBOE on the effective date of the acquisition, the Company acquired these properties for approximately $9.66 per BOE of estimated proved reserves.

Wyoming and Utah Properties—On September 30, 2004, the Company acquired interests in three operated fields in Wyoming and Utah. The purchase price was $35.0 million in cash and was funded under the Company's bank credit agreement. Based on the purchase price of $35.0 million and estimated proved reserves of 5.1 MMBOE on the effective date of the acquisition, the Company acquired these properties for approximately $6.84 per BOE of estimated proved reserves.

Mississippi Properties—On November 3, 2004, the Company acquired an interest in the Lake Como field in Mississippi. The purchase price was $12.0 million in cash and was funded under the Company's bank credit agreement. Based on the purchase price of $12.0 million and estimated proved reserves of 1.8 MMBOE on the effective date of the acquisition, the Company acquired these properties for approximately $6.78 per BOE of estimated proved reserves.

Additional Permian Basin Interest—On December 31, 2004, the Company acquired an additional working interest in the Would Have field in Texas. The purchase price was $7.0 million in cash and was funded under the Company's bank credit agreement. Based on the purchase price and estimated proved reserves of 0.7 MBOE on the effective date of the acquisition, the Company acquired these properties for approximately $10.32 per BOE of estimated proved reserves.

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 preliminary allocation of the purchase price for each 2004 purchase transaction based on the acquisition date fair values of the assets acquired and the liabilities assumed (in thousands).

	Permian Basin	Equity Oil	Other Cash Acquisitions
Purchase Price:			
Cash paid, net of cash received	$345,000	$ 256	$ 117,500
Debt assumed	—	29,000	—
Stock issued	—	43,298	—
Total	$345,000	$ 72,554	$ 117,500
Allocation of Purchase Price:			
Working capital	$ —	$ 3,277	$ —
Oil and gas properties	345,000	83,205	117,500
Deferred income taxes	—	(11,075)	—
Other non-current liabilities, net	—	(2,853)	—
Total	$345,000	$ 72,554	$ 117,500

Each of the business combinations completed during the past two years consisted of oil and natural gas properties or companies with oil and natural gas interests. The consideration 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 purchase, with no consideration being allocated to goodwill.

Acquisition Pro Forma

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 results of operations for the year ended December 31, 2004 reflects all of the above acquisitions as though they had occurred on January 1, 2004. The pro forma information includes numerous assumptions and is not necessarily indicative of future results of operations:

	Year Ended December 31, 2005		2004	
	As Reported	Pro Forma	As Reported	Pro Forma
	(In thousands, except per common share data)			
Total Revenues and other income	$540,448	$652,634	$282,140	$501,586
Net income	121,922	155,462	70,046	106,063
Net income per common share- basic	3.89	4.05	3.38	3.82
Net income per common share-diluted	3.88	4.04	3.38	3.81

3. ASSET RETIREMENT OBLIGATIONS

Effective January 1, 2003, the Company adopted the provisions of SFAS No. 143, *Accounting for Asset Retirement Obligations*. This statement generally applies to legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. Upon adoption of SFAS No. 143, the Company recorded an increase to its discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million). The Company had an additional $4.2 million asset retirement obligation accrued at January 1, 2003 relating to its retained obligation with respect to the Point Arguello facility located offshore from California.

The following table provides a reconciliation of the Company's asset retirement obligations for the years ended December 31, 2005 and 2004.

	Year Ended December 31, 2005	Year Ended December 31, 2004
Beginning asset retirement obligation	$ 31,639	$ 23,021
Revisions in estimated cash flows	(9,348)	—
Additional liability incurred	8,086	7,280
Accretion expense	2,364	1,754
Liabilities settled upon plugging and abandoning wells	(495)	(416)
Ending asset retirement obligation	$ 32,246	$ 31,639

4. INVESTMENT IN PARTNERSHIPS

In 2003, the Company purchased limited partnership interests in three limited partnerships in which the Company was already general partner for $4.5 million. Those partnerships were terminated in 2003. In June of 2005, the Company purchased limited partnership interests in another three limited partnerships in which the Company was already a general partner for $30.5 million, thereby increasing its ownership in all three partnerships to 100%. Subsequently in 2005, the Company terminated those partnerships. Additionally, Whiting owns an interest in two partnerships that operate pipelines transporting carbon dioxide.

5. RELATED PARTY TRANSACTIONS

In conjunction with the Company's initial public offering in November 2003, the Company issued a promissory note payable to Alliant Energy in the aggregate principal amount of $3.0 million. The note bears interest at an annual rate of 5%. The Company paid all principal and interest on the promissory note on November 25, 2005.

Alliant Energy had loaned the Company an aggregate $80.5 million as of December 31, 2002. The note bore interest at a floating rate which ranged from 6.9% to 4.4% during 2003, respectively. On March 31, 2003, Alliant Energy converted its outstanding intercompany balance of $80.9 million to equity of the Company. The Company incurred $1.2 million in interest expense related to this note during the year ended December 31, 2003.

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

6. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2005 and 2004:

	2005	2004
Credit agreement	$260,000	$175,000
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $848 and $1,022 as of December 31, 2005 and 2004, respectively	148,014	150,261
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $2,916	217,084	—
7% Senior Subordinated Notes due 2014	250,000	—
Alliant Energy	—	3,167
Total	875,098	328,428
Current portion of long-term debt	—	(3,167)
Long-term debt	$875,098	$325,261

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, 2005, had a borrowing base of $787.5 million. The borrowing base under the credit agreement is determined in the discretion of the lenders based on the collateral value of the proved reserves, 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, 2005, the outstanding principal balance under the credit agreement was $260.0 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 from time to 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 from time to time in an aggregate amount not to exceed $50.0 million. As of December 31, 2005, letters of credit totaling $0.3 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. Whiting Oil and Gas 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, 2005, the weighted average interest rate on the entire outstanding principal balance under the credit agreement was 5.3%.

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 (as defined in the credit agreement) ratio 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 Equity Oil Company to make any dividends, distributions, principal payments on senior notes, or other payments to the Company. 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, 2005. 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 its wholly-owned subsidiary, 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 included in the borrowing base for the credit agreement as security for its guarantee.

Senior Subordinated Notes— On October 4, 2005, the Company issued $250.0 million aggregate principal amount of 7% Senior Subordinated Notes due 2014. The 7% Senior Subordinated Notes due 2014 were issued at par. The Company used the net proceeds from this debt offering and the common stock offering to pay the cash portion of the purchase price for the acquisition of the North Ward Estes and ancillary properties and to repay $100.0 million of debt under Whiting Oil and Gas' credit agreement that was incurred in connection with the acquisition of Postle. Based on the market price of the 7% Senior Subordinated Notes due 2014, their estimated fair value was $250.0 million as of December 31, 2005.

On April 19, 2005, the Company issued $220.0 million aggregate principal amount of its 7.25% Senior Subordinated Notes due 2013. The 7.25% Senior Subordinated Notes due 2013 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 the notes yielding an effective interest rate of 7.5%. Based on the market price of the 7.25% Senior Subordinated Notes due 2013, their estimated fair value was $223.0 million as of December 31, 2005.

In May 2004, the Company issued $150.0 million aggregate principal amount of its 7.25% Senior Subordinated Notes due 2012. The 7.25% Senior Subordinated Notes due 2012 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 the notes yielding an effective interest rate of 7.4%. Based on the market price of the 7.25% Senior Subordinated Notes due 2012, their estimated fair value was $152.1 million as of December 31, 2005.

The notes are unsecured obligations of the Company and are subordinated to all of the Company's senior debt. The indentures governing the notes contain various restrictive covenants that are substantially identical and may limit the Company's and its subsidiaries' 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 limit the discretion of the Company's management in operating the Company's business. In addition, Whiting Oil and Gas' credit agreement restricts the ability of the Company's subsidiaries to make certain payments, including principal on the notes, to the Company. The Company was in compliance with these covenants as of December 31, 2005. Three of the Company's 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 the Company has no independent assets or operations.

Interest Rate Swap—In August 2004, the Company entered into an interest rate swap contract to hedge the fair value of $75 million of its 7.25% Senior Subordinated Notes due 2012, which had the effect of reducing the effective interest rate on these notes to 6.6% at December 31, 2005. Because this swap meets the conditions to qualify for the "short cut" method of assessing effectiveness under the provisions of Statement of Financial Accounting Standards No. 133, 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, 2005 was 4.69%. As of December 31, 2005, the Company has recorded a long term liability of $1.1 million related to the interest rate swap, which has been designated as a fair value hedge, with an offsetting reduction in the fair value of the 7.25% Senior Subordinated Notes due 2012.

7. STOCKHOLDERS' EQUITY

Common Stock Offerings—On October 4, 2005, the Company completed its public offering of 6,612,500 shares of its common stock. The offering was priced at $43.60 per share to the public. The number of shares includes the sale of 862,500 shares pursuant to the exercise of the underwriters' over-allotment option. The Company used the net proceeds from the offering of $277.0 million along with the proceeds from the 7% Senior Subordinated Notes to pay the cash portion of the purchase price for the acquisition of the North Ward Estes and ancillary properties and to repay $100.0 million of debt outstanding under Whiting Oil and Gas' credit agreement that was incurred in connection with the acquisition of the Postle properties.

On November 22, 2004, the Company completed its public offering of 8,625,000 shares of its common stock. The offering was priced at $29.02 per share to the public. The number of shares includes the sale of 1,125,000 shares pursuant to the exercise of the underwriters' over-allotment option. The Company used the net proceeds from the offering of $239.7 million and cash on hand to repay $240.0 million of debt outstanding under the credit.

Equity Incentive Plan — The Company maintains the Whiting Petroleum Corporation 2003 Equity Incentive Plan, pursuant to which two million shares of the Company's common stock have been reserved for issuance. No participating employee 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. This plan prohibits the repricing of outstanding stock options without stockholder approval. During 2004, the Company granted 112,921 shares of restricted stock under this plan and 7,724 shares were forfeited. The shares of restricted stock were recorded at fair value of $2.3 million, net of forfeitures. During 2005, the Company granted 84,652 shares of restricted stock under this plan, 9,265 shares were forfeited and 6,122 shares were cancelled when used for employee tax withholdings. The shares of restricted stock were recorded at fair value of $3.2 million, net of forfeitures. All grants are being amortized to general and administrative expense over their three-year vesting period.

Phantom Equity Plan — The Company had a phantom equity plan as an incentive to employees. The phantom equity plan award was calculated based on the growth of the Company's proved oil and natural gas reserves before income taxes from January 1, 2000 to a triggering event, less increases in debt for the same period (the "Value Appreciation"). The Value Appreciation was then multiplied by a sharing percentage of 5%. The completion of the initial public offering in November 2003 constituted a triggering event under the plan and, consequently, the Company's employees received a $10.9 million award in the form of approximately 420,000 shares of Whiting common stock after withholding of shares for payroll and income taxes. Alliant Energy was required to fund the majority of plan expense by contributing cash and stock to the Company in the combined amount of $10.7 million, which was reflected as an increase to additional paid-in capital. The phantom equity plan is now terminated.

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. The dividend is payable upon the close of business on March 9, 2006 to the stockholders of record on 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 par value ("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 $.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.

8. EMPLOYEE BENEFIT PLANS

Production Participation Plan **—** The Company has a Production Participation Plan (the "Plan") for all employees. On an annual basis, interests in oil and natural 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 natural 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. General and administrative expense related to current distributions under the Plan amounted to $12.1 million, $7.1 million and $4.4 million for 2005, 2004 and 2003, respectively.

Prior to Plan year 2004, employees who terminated employment generally vested in future payments attributable to their interests bases on their tenure with the Company over their initial five years of employment and forfeitures were re-allocated to remaining Plan participants. The Plan was modified in 2004 to provide that (1) for years 2004 and after, employees who terminate with the Company will vest at a rate of 20% per year from the beginning of the Plan year with respect to future payments attributable to their interests with respect to the income allocated to the Plan for such year; (2) employees will become fully vested at age 65, regardless of when their interests would otherwise vest; and (3) for years 2004 and after, any forfeitures would inure to the benefit of the Company.

The Company uses average historical prices to estimate the vested long-term Production Participation Plan liability. At December 31, 2005, the company used five year average historical NYMEX prices of $39.75 for crude oil and $5.36 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 the fair market value of their respective interest 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, 2005, 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 $65.8 million. This amount includes $10.6 million attributable to proved undeveloped oil and natural gas properties. The ultimate sharing contribution for proved undeveloped oil and natural gas properties will be awarded in the year of Plan termination or change of control. The Company has no intention to terminate the Plan. The following table presents changes in the estimated long-term liability related to the Plan:

	Year Ended December 31,	
	2005	2004
Beginning Production Participation Plan liability	$ 9,579	$ 7,868
Change in liability for accretion and change in estimate	21,829	8,826
Reduction in liability for cash payments made or accrued and recognized as compensation expense	(12,121)	(7,115)
Ending Production Participation Plan liability	$ 19,287	$ 9,579

The Company records the expense associated with changes in the present value of estimated future payments under the Plan as a separate line item in the consolidated statements of income. The amount recorded is not allocated to general and administrative expense or exploration expense because the adjustment of the liability is associated with the future net cash flows from the oil and natural gas properties rather than current period performance. The table below presents the estimated allocation of the change in the liability if the Company did allocate the adjustment to these specific line items:

	2005	2004	2003
General and administrative expense	$ 8,186	$ 1,574	$ (174)
Exploration expense	1,522	137	(11)
Total	$ 9,708	$ 1,711	$ (185)

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 2005, 2004 and 2003 were $1.2 million, $0.7 million and $0.7 million, respectively. Employer contributions vest ratably at 20% per year over a five year period.

9. INCOME TAXES

Deferred tax assets and liabilities are measured by applying the provisions of enacted tax laws to determine the amount of taxes payable or refundable currently or in future years related to cumulative temporary differences between the tax bases of assets and liabilities and amounts reported in the Company's balance sheet. The tax effect of the net change in the cumulative temporary differences during each period in the deferred tax assets and liability determines the periodic provision for deferred taxes.

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 of $5.4 million were generated in 2002 and are expected to be utilized by Alliant Energy in the future. However, on a stand-alone basis Whiting would have been unable to use the credits in its 2002 tax return. Under the Company's tax separation and indemnification agreement with Alliant Energy, the Company will be paid for the Section 29 credits when Alliant Energy receives the benefit for them. The Company has recorded a long-term asset for these credits.

Income tax expense differed from amounts computed by applying the U.S. Federal income tax rate as follows (in thousands):

	2005	2004	2003
Expected statutory tax expense at 35%	$ 68,635	$ 39,902	$ 12,649
State tax expense, net of federal benefit	7,028	4,100	1,516
Benefits of tax credits	(929)	—	—
Statutory depletion	(434)	(53)	(216)
Other	(123)	10	—
	$ 74,176	$ 43,959	$ 13,949

Temporary differences between the financial statement carrying amounts and tax bases of assets and liabilities that give rise to the net deferred tax asset (liability) result from the following components (in thousands):

	2005	2004	2003
Oil and gas properties	$(127,337)	$(57,283)	$ (2,893)
Production Participation Plan	7,445	3,698	2,993
Available for sale securities	—	—	(127)
Derivative instruments	21,766	645	828
Tax sharing agreement	11,129	12,036	11,028
Abandonment obligations	9,591	9,356	3,028
Restricted stock compensation	1,035	—	—
Net operating loss carryforward	—	—	3,878
Other	(85)	(365)	—
Total net deferred income tax (liability) asset	(76,456)	(31,913)	18,735
Current deferred income tax asset	15,121	2,368	—
Long-term deferred income tax (liability) asset	$ (91,577)	$(34,281)	$ 18,735

Substantially all of the Company's net operating loss generated during the 2003 tax year was utilized during 2004.

10. COMMITMENTS AND CONTINGENCIES

The Company leases 87,000 square feet of administrative office space under an operating lease arrangement through October 31, 2010 and an additional 23,000 square feet of office space in Midland, Texas. Rental expense for 2005, 2004 and 2003 amounted to $1.5 million, $0.9 million and $1.1 million, respectively. A summary of future minimum lease payments under its non-cancelable operating lease as of December 31, 2005 is as follows (in thousands):

Year Ending December 31, 2006	$ 1,701
Year Ending December 31, 2007	1,682
Year Ending December 31, 2008	1,481
Year Ending December 31, 2009	1,469
Year Ending December 31, 2010	1,224
Total	$ 7,557

The Company is subject to litigation claims and governmental and regulatory controls 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 financial position, cash flows or results of operations.

In July, 2005, the Company entered into a 9.5 year take-or-pay supply agreement, whereby the Company has committed to buy certain volumes of CO_2 for a fixed fee, subject to annual escalation, for use in enhanced recovery projects on its Postle field in Texas County, Oklahoma. Under the terms of the agreement, the Company is obligated to purchase a minimum daily volume of CO_2 or else pay for any deficiencies at the price in effect when delivery was to have occurred. As calculated on an annual basis, Whiting's failure to purchase the minimum CO_2 volumes requires the Company to pay the supplier for any deficiency. The CO_2 volumes planned for use in the Postle field enhanced recovery projects currently exceed the minimum daily volumes provided in this take-or-pay supply agreement. Therefore, the Company expects to avoid any payments for deficiencies. As of December 31, 2005, commitments under the supply agreement amounted to $77.5 million through 2014.

During 2005, the Company entered into three separate three year agreements, with total commitments of $26.4 million, for rigs drilling in the U.S. Rocky Mountain region. Early termination of these contracts at December 31, 2005 would have required maximum penalties of $14.1 million. No other drilling rigs working for the Company are currently under long-term contracts or contracts which cannot be terminated at the end of the well that is currently being drilled.

The Company, as part of a 2002 purchase transaction, agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2006 increased to 50% of the actual price received in excess of $20.56 per barrel. Approximately 39,200 net barrels of crude oil per month are currently subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. During the years 2005, 2004 and 2003, the Company paid $7.6 million, $4.8 million and $2.3 million, respectively, under this agreement. As of December 31, 2005 and 2004, the Company had accrued an additional $0.7 million and $0.5 million, respectively, as currently payable.

Tax Separation and Indemnification Agreement with Alliant Energy—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 the assets of Whiting and its subsidiaries 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 the Company's 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. Future tax benefits in total will approximate $64.6 million. The Company has estimated total payments to Alliant will approximate $49.2 million given the discounting effect of the final payment in 2014.

The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders' equity. The Company monitors the estimate of when payments will be made and adjusts the accretion of this liability prospectively. During 2004, the Company did not make any payments under this agreement but did recognize $2.4 million of accretion expense which is included as a component of interest expense. During 2005, the Company made a payment of $5.1 million under this agreement and recognized additional accretion expense of $2.7. The Company's estimate of payments to be made in 2006 under this agreement of $4.3 is reflected as a current liability at December 31, 2005.

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 change will occur during the term of this agreement.

11. OIL AND GAS ACTIVITIES

The Company's oil and natural gas activities are almost entirely within the United States. The Company owns a nonoperated working interest in one field in Canada that represents less than 1% of its total reserve base. Costs incurred in oil and natural gas producing activities are as follows (in thousands):

	2005	2004	2003
Unproved property acquisition	$ 16,124	$ 4,401	$ 242
Proved property acquisition	906,208	525,563	11,823
Development	215,162	74,476	40,423
Exploration	22,532	9,739	3,186
Total	$1,160,026	$614,179	$ 55,674

During 2005, 2004 and 2003, additions to oil and natural gas properties of $8.1 million, $7.3 million and $1.0 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 natural gas producing activities are summarized as follows (in thousands):

	2005	2004	2003
Proven oil and gas properties	$2,353,372	$1,225,676	$ 615,764
Unproven oil and gas properties	21,671	6,038	1,637
Accumulated depreciation, depletion and amortization	(334,825)	(242,108)	(191,488)
Oil and gas properties—net	$2,040,218	$ 989,606	$ 425,913

During 2003, the Company recorded an addition to oil and natural gas properties of $10.1 million for the asset retirement costs related to the adoption of SFAS No. 143.

In April 2005, the Financial Accounting Standards Board ("FASB") issued FASB Staff Position No. FAS 19-1, *Accounting for Suspended Well Costs* ("FSP 19-1"), which amends FAS 19, *Financial Accounting and Reporting by Oil and Gas Producing Companies*. During the third quarter of 2005, the Company adopted the requirements of FSP 19-1. Upon adoption, the Company evaluated all existing capitalized well costs under the provisions of FSP 19-1 and determined there was no impact to the Company's consolidated financial statements. The following table reflects the net changes in capitalized exploratory well costs during 2005 and 2004.

	2005	2004
Beginning balance at January 1	$ 2,937	$ —
Additions to capitalized exploratory well costs pending the determination of proved reserves	6,500	5,562*
Reclassifications to wells, facilities and equipment based on the determination of proved reserves	(5,244)	(2,625)
Capitalized exploratory well costs charged to expense	—	—*
Ending balance at December 31	$ 4,193	$ 2,937

* Amounts revised by $641 from that reported in the Company's 2004 Annual Report on Form 10-K due to changes between the draft FSP 19-a and the final FSP19-1. The final FSP directs that costs suspended and expensed in the same annual period not be included in this analysis. Amounts for the year ended December 31, 2003 have not been presented as all exploratory well costs were suspended and expensed during 2003.

At December 31, 2005, the Company had no exploratory well costs capitalized for a period of greater than one year after the completion of drilling.

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

The estimate of proved reserves and related valuations were based upon the reports of Ryder Scott Company L.P., Cawley, Gillespie & Associates, Inc., R. A. Lenser & Associates, Inc., and Netherland, Sewell & Associates, Inc., each independent petroleum and geological engineers, and the Company's engineering staff, in accordance with the provisions of Statement of Financial Accounting Standards No. 69 ("SFAS No. 69"), *Disclosures about Oil and Gas Producing Activities*. 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.

Substantially all of the Company's oil and natural gas reserves are attributable to properties within the United States. The volumes below include one field in Canada with total estimated proved reserves of 800 MBOE at December 31, 2005. A summary of the Company's changes in quantities of proved oil and natural gas reserves for the years ended December 31, 2005, 2004 and 2003, are as follows:

	Oil (Mbbl)	Natural Gas (MMcf)
Balance—January 1, 2003	29,458	235,988
Extensions and discoveries	2,327	17,097
Sales of minerals in place	—	—
Purchases of minerals in place	822	3,996
Production	(2,594)	(21,596)
Revisions to previous estimates	4,627	(4,474)
Balance—December 31, 2003	34,640	231,011
Extensions and discoveries	5,175	29,133
Sales of minerals in place	—	(70)
Purchases of minerals in place	52,288	114,715
Production	(3,662)	(25,071)
Revisions to previous estimates	(853)	(9,862)
Balance—December 31, 2004	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
Proved developed reserves:		
December 31, 2003	26,157	171,881
December 31, 2004	60,625	242,662
December 31, 2005	111,954	267,429

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 natural gas reserve volumes that have been allocated to the Production Participation 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 net income from the oil and natural gas production allocated to the Plan.

The standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and natural gas reserves were prepared in accordance with the provisions of 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 natural 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 natural gas reserves, less the tax basis of properties involved. Future income tax expenses give effect to permanent differences, tax credits and loss carryforwards relating to the proved oil and natural gas reserves. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of the Company's oil and natural gas properties.

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

	2005	2004	2003
Future cash flows	$14,294,674	$ 5,445,781	$2,297,935
Future production costs	(4,484,415)	(1,804,161)	(879,390)
Future development costs	(909,093)	(216,864)	(66,326)
Future income tax expense	(2,773,077)	(996,035)	(336,165)
Future net cash flows	6,128,089	2,428,721	1,016,054
10% annual discount for estimated timing of cash flows	(3,245,188)	(1,116,667)	(426,490)
Standardized measure of discounted future net cash flows	$ 2,882,901	$ 1,312,054	$ 589,564

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 $7.3 million in 2005, $0.0 in 2004 and $0.1 million in 2003.

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

	2005	2004	2003
		(in thousands)	
Beginning of year	$1,312,054	$ 589,564	$ 476,029
Sale of oil and gas produced, net of production costs	(425,594)	(210,052)	(121,827)
Sales of minerals in place	—	(122)	—
Net changes in prices and production costs	557,908	174,511	108,115
Extensions, discoveries and improved recoveries	104,609	153,444	47,183
Development costs-net	(361,356)	(150,537)	(886)
Purchases of mineral in place	2,321,289	973,959	16,745
Revisions of previous quantity estimates	(115,617)	(33,999)	43,679
Net change in income taxes	(766,485)	(343,023)	(42,082)
Accretion of discount	185,014	78,462	62,901
Changes in production rates and other	71,079	79,847	(293)
End of year	$2,882,901	$1,312,054	$ 589,564

Average wellhead prices in effect at December 31, 2005, 2004 and 2003 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows (in thousands):

	2005	2004	2003
Oil (per Bbl)	$55.10	$40.58	$29.43
Gas (per Mcf)	$ 7.97	$ 5.56	$ 5.52

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13. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2005 and 2004 (in thousands except per share data) (in thousands):

	Three Months Ended			
	March 31, 2005	**June 30, 2005**	**September 30, 2005**	**December 31, 2005**
Year ended December 31, 2005:				
Oil and gas sales	$105,465	$115,978	$ 153,386	$ 198,417
Net income	26,055	24,238	33,282	38,347
Basic and diluted net income per share	0.88	0.82	1.12	1.05

	Three Months Ended			
	March 31, 2004	**June 30, 2004**	**September 30, 2004**	**December 31, 2004**
Year ended December 31, 2004:				
Oil and gas sales	$ 47,636	$ 52,874	$ 65,898	$ 114,649
Net income	9,638	13,471	14,317	32,620
Basic and diluted net income per share	0.51	0.72	0.70	1.31

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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, 2005. 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, 2005 to ensure that (a) information required to be disclosed 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 (b) material information relating to us, including our consolidated subsidiaries, was made known to them by others within those entities, particularly during the period in which this Annual Report on Form 10-K was being prepared.

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, 2005 that has materially affected, or is reasonably likely to materially affect, our internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors and Executive Officers of the Registrant

The information included under the captions "Election of Directors," "Board of Directors and Corporate Governance" and "Section 16(a) Beneficial Ownership Reporting Compliance", respectively, in our definitive Proxy Statement for Whiting Petroleum Corporation's 2005 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 – Director Compensation” 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, 2005.

Plan Category	Number of securities to be issued upon the 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)	-0-	N/A	1,819,416(2)
Equity compensation plans not approved by security holders	—	N/A	—
Total	-0-	N/A	1,819,416(2)

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

(2) Excludes 151,890 shares of restricted common stock previously issued and outstanding for which the restrictions have not lapsed.

Item 13. Certain Relationships and Related Transactions

Not applicable.

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, 2005 and 2004

c. Consolidated Statements of Income for the Years ended December 31, 2005, 2004 and 2003

d. Consolidated Statements of Stockholders' Equity and Comprehensive Income for the Years ended December 31, 2005, 2004 and 2003

e. Consolidated Statements of Cash Flows for the Years ended December 31, 2005, 2004 and 2003

f. Notes to Consolidated Financial Statements

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

a. Schedule I – Condensed Financial Information of Registrant

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

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

(b) Exhibits

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

(c) Financial Statement Schedules.

Schedule I

WHITING PETROLEUM CORPORATION
CONDENSED FINANCIAL INFORMATION OF REGISTRANT
BALANCE SHEETS
(In thousands)

	Year Ended December 31, 2005	2004
ASSETS		
CURRENT ASSETS:		
Deferred income taxes	$ 15,121	$ 2,368
Prepaid expense and other	2,713	—
	17,834	2,368
LONG-TERM ASSETS:		
Investment in subsidiaries	711,320	482,433
Intercompany receivable	1,001,319	341,819
Debt issue cost	12,642	4,772
TOTAL	$ 1,743,115	$ 831,392
LIABILITIES AND STOCKHOLDERS' EQUITY		
CURRENT LIABILITIES:		
Accrued interest	$ 8,610	$ 1,400
Current portion of tax sharing liability	4,254	4,214
Current portion of long-term debt	—	3,167
Total current liabilities	12,864	8,781
LONG-TERM DEBT	616,236	148,978
TAX SHARING LIABILITY	24,576	26,966
DEFERRED INCOME TAXES	91,577	34,281
STOCKHOLDERS' EQUITY:		
Common stock, $.001 par value; 75,000,000 shares authorized, 36,841,823 and 29,717,808 shares issued and outstanding as of December 31, 2005 and 2004, respectively	37	30
Additional paid-in capital	753,093	455,635
Accumulated other comprehensive loss	(34,620)	(1,025)
Deferred compensation	(2,031)	(1,715)
Retained earnings	281,383	159,461
Total stockholders' equity	997,862	612,386
TOTAL	$ 1,743,115	$ 831,392

See notes to condensed financial information of registrant.

Table of Contents

WHITING PETROLEUM CORPORATION
CONDENSED FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF OPERATIONS
FOR THE YEARS ENDED DECEMBER 31, 2005 AND 2004 AND THE PERIOD FROM NOVEMBER 25, 2003 TO DECEMBER 31, 2003
(In thousands)

	2005	2004	2003
OPERATING EXPENSES:			
General and administrative	$ (2,861)	$ (580)	$ —
INTEREST EXPENSE	(29,928)	(8,998)	(220)
EQUITY IN EARNINGS (LOSSES) OF SUBSIDIARIES	228,887	123,583	(7,436)
INCOME (LOSS) BEFORE INCOME TAXES	196,098	114,005	(7,656)
INCOME TAX EXPENSE (BENEFIT)	74,176	43,959	(2,955)
NET INCOME (LOSS)	$ 121,922	$ 70,046	$ (4,701)

See notes to condensed financial information of registrant.

WHITING PETROLEUM CORPORATION
CONDENSED FINANCIAL INFORMATION OF REGISTRANT
STATEMENTS OF CASH FLOWS
FOR THE YEARS ENDED DECEMBER 31, 2005 AND 2004 AND THE PERIOD FROM NOVEMBER 25, 2003 TO DECEMBER 31, 2003
(In thousands)

	2005	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	$ 121,922	$ 70,046	$ (4,701)
Equity in (earnings) losses of subsidiaries	(228,887)	(123,583)	7,436
Deferred income taxes	65,662	40,077	(2,955)
Amortization of debt issuance costs and debt discount	1,956	501	—
Amortization of deferred compensation	2,861	580	—
Accretion of tax sharing agreement	2,725	2,390	220
Prepaid expense and other	(2,713)	—	—
Change in accrued interest	7,210	1,550	—
Net cash used in operating activities	(29,264)	(8,439)	—
CASH FLOWS FROM INVESTING ACTIVITIES:			
Investment in subsidiaries	—	—	—
CASH FLOWS FROM FINANCING ACTIVITIES:			
Repayments to Alliant	(8,242)	—	—
Issuance of common stock	277,117	239,686	—
Issuance of 7.25% Senior Subordinated Notes due 2012	—	148,890	—
Issuance of 7.25% Senior Subordinated Notes due 2013	216,715	—	—
Issuance of 7% Senior Subordinated Notes due 2014	250,000	—	—
Intercompany receivable	(697,039)	(374,952)	—
Debt issuance costs	(9,283)	(5,185)	—
Restricted stock used for tax withholdings	(241)	—	—
Net tax effect arising from restricted stock activity	237	—	—
Net cash provided by financing activities	29,264	8,439	—
NET CHANGE IN CASH AND CASH EQUIVALENTS	—	—	—
CASH AND CASH EQUIVALENTS:			
Beginning of period	—	—	—
End of period	$ —	$ —	$ —

See notes to condensed financial information of registrant.

WHITING PETROLEUM CORPORATION
NOTES TO CONDENSED FINANCIAL INFORMATION OF REGISTRANT
FOR THE YEARS ENDED DECEMBER 31, 2005 AND 2004 AND THE PERIOD FROM NOVEMBER 25, 2003 TO DECEMBER 31, 2003

1. GENERAL

Whiting Petroleum Corporation, formerly known as Whiting Petroleum Holdings, Inc. (the "Company"), was incorporated in the state of Delaware on July 18, 2003. The Company was formed for the sole purpose of becoming a holding company of Whiting Oil and Gas Corporation, formerly known as Whiting Petroleum Corporation ("Whiting Oil and Gas"). Whiting Oil and Gas is an oil and natural gas exploration and development company that was, until November 25, 2003, a wholly owned subsidiary of Alliant Energy Resources, Inc. ("Resources"). On November 25, 2003, the Company completed an initial public offering of its common stock (the "IPO"). Immediately prior to the IPO, Resources transferred all of the outstanding stock of Whiting Oil and Gas to the Company in exchange for 18,330,000 shares of common stock issued by the Company, which constituted all of the Company's outstanding stock, and a promissory note in the aggregate principal amount of $3.0 million. Resources then sold 17,250,000 shares of the Company's common stock in the IPO. Prior to November 25, 2003, the Company conducted no activities other than its formation and held no assets. As a result, financial statements for the Company for periods prior to November 25, 2003 are not presented as part of the accompanying condensed financial statements of the Company.

The accompanying condensed financial statements of the Company should be read in conjunction with the consolidated financial statements of the Company and its subsidiaries included in the Company's Annual Report on Form 10-K for the year ended December 31, 2005.

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.

2. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2005 and 2004:

	2005	2004
7.25% Senior Subordinated Notes due 2012, net of unamortized debt discount of $848 and $1,022 as of December 31, 2005 and 2004, respectively	149,152	148,978
7.25% Senior Subordinated Notes due 2013, net of unamortized debt discount of $2,916	217,084	—
7% Senior Subordinated Notes due 2014	250,000	—
Total	$ 616,236	$ 148,978

Senior Subordinated Notes— On October 4, 2005, the Company issued $250.0 million aggregate principal amount of 7% Senior Subordinated Notes due 2014. The 7% Senior Subordinated Notes due 2014 were issued at par. The Company used the net proceeds from this debt offering and the common stock offering to pay the cash portion of the purchase price for the acquisition of the North Ward Estes and ancillary properties and to repay $100.0 million of debt under Whiting Oil and Gas' credit agreement that was incurred in connection with the acquisition of Postle. Based on the market price of the 7% Senior Subordinated Notes due 2014, their estimated fair value was $250.0 million as of December 31, 2005.

On April 19, 2005, the Company issued $220.0 million aggregate principal amount of its 7.25% Senior Subordinated Notes due 2013. The 7.25% Senior Subordinated Notes due 2013 were issued at 98.507% of par and the associated discount is being amortized to interest expense over the term of the notes. Based on the market price of the 7.25% Senior Subordinated Notes due 2013, their estimated fair value was $223.0 million as of December 31, 2005.

In May 2004, the Company issued $150.0 million aggregate principal amount of its 7.25% Senior Subordinated Notes due 2012. The 7.25% Senior Subordinated Notes due 2012 were issued at 99.26% of par and the associated discount is being amortized to interest expense over the term of the notes. Based on the market price of the 7.25% Senior Subordinated Notes due 2012, their estimated fair value was $152.1 million as of December 31, 2005.

The notes are unsecured obligations of the Company and are subordinated to all of the Company's senior debt. The indentures governing the notes contain various restrictive covenants that are substantially identical and may limit the Company's and its subsidiaries' 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 limit the discretion of the Company's management in operating the Company's business. In addition, Whiting Oil and Gas' credit agreement restricts the ability of the Company's subsidiaries to make certain payments, including principal on the notes, to the Company. The Company was in compliance with these covenants as of December 31, 2005. Three of the Company's operating subsidiaries, Whiting Oil and Gas Corporation, 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 the Company has no independent assets or operations.

3. COMMITMENTS AND CONTINGENCIES

The Company is subject to litigation claims and governmental and regulatory controls 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 financial position or results of operations.

Tax Separation and Indemnification Agreement with Alliant Energy—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 basis of the assets of Whiting and its subsidiaries 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 basis of the Company's assets. This additional basis is 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. Future tax benefits in total will approximate $64.6 million. The Company has estimated total payments to Alliant will approximate $49.2 million given the discounting effect of the final payment in 2014.

The Company has discounted all cash payments to Alliant at the date of the Tax Separation and Indemnification Agreement.

The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders' equity. The Company will monitor the estimate of when payments will be made and adjust the accretion of this liability on a prospective basis. During 2004, the Company did not make any payments under this agreement but did recognize $2.4 million of accretion expense which is included as a component of interest expense. During 2005, the Company made a payment of $5.1 million under this agreement and recognized additional accretion expense of $2.7. The Company's estimate of payments to be made in 2006 under this agreement of $4.3 is reflected as a current liability at December 31, 2005.

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 change will occur during the term of this agreement.

******

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, 2006.

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, 2006
/s/ Michael J. Stevens Michael J. Stevens	Vice President and Chief Financial Officer (Principal Financial Officer)	February 28, 2006
/s/ Brent P. Jensen Brent P. Jensen	Controller and Treasurer (Principal Accounting Officer)	February 28, 2006
/s/ Thomas L. Aller Thomas L. Aller	Director	February 28, 2006
/s/ Graydon D. Hubbard Graydon D. Hubbard	Director	February 28, 2006
/s/ J.B. Ladd J. B. Ladd	Director	February 28, 2006
/s/ Palmer L. Moe Palmer L. Moe	Director	February 28, 2006
/s/ Kenneth R. Whiting Kenneth R. Whiting	Director	February 28, 2006

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 [Incorporated by reference to Exhibit 10.11 to Whiting Petroleum Corporation's Registration Statement on Form S-1 (Registration No. 333-107341)].

Exhibit Number	Exhibit Description
(10.2)*	Form of Restricted Stock Agreement pursuant to the Whiting Petroleum Corporation 2003 Equity Incentive Plan [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's quarterly Report on Form 10-Q for the quarter ended September 30, 2004 (File No. 001-31899)].
(10.3)*	Whiting Oil and Gas Corporation Production Participation Plan, as amended and restated February 23, 2006 [Incorporated by reference to Exhibit 10.1 to Whiting Petroleum Corporation's Current Report on Form 8-K dated February 23, 2006 (File No. 001-31899)].
(10.4)	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)].
(10.5)*	Summary of 2006 Non-Employee Director Compensation for Whiting Petroleum Corporation. [Incorporated by reference to Exhibit 10.2 to Whiting Petroleum Corporation's Current Report on Form 8-K February 23, 2006 (File No. 001-31899)].
(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.
(23.3)	Consent of R.A. Lenser & Associates, Inc., Independent Petroleum Engineers.
(23.4)	Consent of Ryder Scott Company, L.P., Independent Petroleum Engineers.
(23.5)	Consent of Netherland, Sewell & Associates, Inc., Independent Petroleum Engineers.
(31.1)	Certification by Chairman, President and Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act.
(31.2)	Certification by the Vice President of Finance 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 of Finance and Chief Financial Officer pursuant to 18 U.S.C. Section 1350
(99.1)	Proxy Statement for the 2006 Annual Meeting of Stockholders, to be filed within 120 days of December 31, 2005 [To be filed with the Securities and Exchange Commission under Regulation 14A within 120 days after December 31, 2005; except to the extent specifically incorporated by reference, the Proxy Statement for the 2006 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]

* A management contract or compensatory plan or arrangement.

Exhibit 12.1

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES
Ratio of Earnings to Fixed Charges
(dollars in thousands)

	Year Ended December 31,				
	2005	**2004**	**2003**	**2002**	**2001**
Fixed Charges:					
Interest Expensed	$ 35,245	$ 11,800	$ 7,867	$ 10,867	$ 10,233
Interest Capitalized	—	200	—	—	210
Amortized Premiums, Discounts and Capitalized Expenses Related to Indebtedness	6,802	4,056	1,310	71	—
Estimate of Interest Within Rental Expense	298	182	209	183	165
Preference Security Dividend Requirements of Subs	—	—	—	—	—
Total Fixed Charges	$ 42,345	$ 16,238	$ 9,386	$ 11,121	$ 10,608
Earnings:					
Pre-tax Income from Continuing Operations	$ 196,098	$114,005	$ 36,139	$ 11,952	$ 54,337
Income from Equity Investees	(409)	—	—	—	—
Fixed Charges (above)	42,345	16,238	9,386	11,121	10,608
Amortization of Capitalized Interest	41	21	21	21	—
Distributed Income of Equity Investees	657	—	—	—	—
Less:					
Interest Capitalized	—	(200)	—	—	(210)
Preference Security Dividend Requirements of Subs	—	—	—	—	—
Minority Interest in Pre-tax income of Subs	—	—	—	—	—
Total earnings	$ 238,732	$130,064	$ 45,546	$ 23,094	$ 64,735
Ratio of Earnings to Fixed Charges (unaudited)	**5.64**	**8.01**	**4.85**	**2.08**	**6.10**

Exhibit 21

SUBSIDIARIES OF WHITING PETROLEUM CORPORATION

Name	Jurisdiction of Incorporation or Organization	Percent Ownership
Whiting Oil and Gas Corporation	Delaware	100%
Equity Oil Company	Colorado	100%
Whiting Programs, Inc.	Delaware	100%

Exhibit 23.1

CONSENT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

We consent to the incorporation by reference in Registration Statement No. 333-111056 on Form S-8, Registration Statement No. 333-121614 on Form S-4 and Registration Statement No. 333-129942 on Form S-4 of our reports dated February 23, 2006, relating to the financial statements and financial statement schedule of Whiting Petroleum Corporation (which report expresses an unqualified opinion and includes an explanatory paragraph referring to a change in Whiting Petroleum Corporation's method of accounting for asset retirement obligations in 2003) and management's report on the effectiveness of internal control over financial reporting, appearing in this Annual Report on Form 10-K of Whiting Petroleum Corporation for the year ended December 31, 2005.

/s/ Deloitte & Touche LLP

Deloitte & Touche LLP
Denver, Colorado
February 27, 2006

Exhibit 23.2

[CAWLEY, GILLESPIE & ASSOCIATES, INC. LETTERHEAD]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Whiting Petroleum Corporation for the year ended December 31, 2005. We hereby further consent to the use of information contained in our report setting forth the estimates of revenues from Whiting Petroleum Corporation's oil and gas reserves as of December 31, 2005. We further consent to the incorporation by reference thereof into Whiting Petroleum Corporation's Registration Statements on Form S-8 (Registration No. 333-111056), Form S-4 (Registration No. 333-121614) and Form S-4 (Registration No. 333-129942).

Sincerely,

/s/ Cawley, Gillespie & Associates, Inc.
Cawley, Gillespie & Associates, Inc.

February 28, 2006

Exhibit 23.3

[R.A. LENSER AND ASSOCIATES, INC. LETTERHEAD]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Whiting Petroleum Corporation for the year ended December 31, 2005. We hereby further consent to the use of information contained in our report setting forth the estimates of revenues from Whiting Petroleum Corporation's oil and gas reserves as of December 31, 2005. We further consent to the incorporation by reference thereof into Whiting Petroleum Corporation's Registration Statements on Form S-8 (Registration No. 333-111056), Form S-4 (Registration No. 333-121614) and Form S-4 (Registration No. 333-129942).

Very truly yours,

R.A. LENSER AND ASSOCIATES, INC.

/s/ Ronald A. Lenser

Ronald A. Lenser, President
Registered Professional Engineer
PE No. 30558

February 28, 2006

Exhibit 23.4

[RYDER SCOTT COMPANY, L.P. LETTERHEAD]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Whiting Petroleum Corporation for the year ended December 31, 2005. We hereby further consent to the use of information contained in our report setting forth the estimates of revenues from Whiting Petroleum Corporation's oil and gas reserves as of December 31, 2005. We further consent to the incorporation by reference thereof into Whiting Petroleum Corporation's Registration Statements on Form S-8 (Registration No. 333-111056), Form S-4 (Registration No. 333-121614) and Form S-4 (Registration No. 333-129942).

Very truly yours,

/s/ Ryder Scott Company, L.P.
Ryder Scott Company, L.P.

February 28, 2006

Exhibit 23.5

[NETHERLAND, SEWELL & ASSOCIATES, INC. LETTERHEAD]

CONSENT OF INDEPENDENT PETROLEUM ENGINEERS AND GEOLOGISTS

The undersigned hereby consents to the references to our firm in the form and context in which they appear in the Annual Report on Form 10-K of Whiting Petroleum Corporation for the year ended December 31, 2005. We hereby further consent to the use of information contained in our report setting forth the estimates of revenues from Whiting Petroleum Corporation's oil and gas reserves as of December 31, 2005. We further consent to the incorporation by reference thereof into Whiting Petroleum Corporation's Registration Statements on Form S-8 (Registration No. 333-111056), Form S-4 (Registration No. 333-121614) and Form S-4 (Registration No. 333-129942).

Sincerely,

NETHERLAND, SEWELL & ASSOCIATES, INC.

/s/ Frederic D. Sewell

Frederic D. Sewell
Chairman and Chief Executive Officer

February 28, 2006

Exhibit 31.1

CERTIFICATIONS

I, James J. Volker, certify that:

1. I have reviewed this Annual Report on Form 10-K of Whiting Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-15(f)) for the registrant and have:

   a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

   b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

   c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

   d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

   a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

   b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2006

/s/ James J. Volker

James J. Volker
Chairman, President and Chief Executive Officer

Exhibit 31.2

CERTIFICATIONS

I, Michael J. Stevens, certify that:

1. I have reviewed this Annual Report on Form 10-K of Whiting Petroleum Corporation;

2. Based on my knowledge, this report does not contain any untrue statement of a material fact or omit to state a material fact necessary to make the statements made, in light of the circumstances under which such statements were made, not misleading with respect to the period covered by this report;

3. Based on my knowledge, the financial statements and other financial information included in this report, fairly present in all material respects the financial condition, results of operations and cash flows of the registrant as of, and for, the periods presented in this report;

4. The registrant's other certifying officer and I are responsible for establishing and maintaining disclosure controls and procedures (as defined in Exchange Act Rules 13a-15(e) and 15d-15(e)) and internal control over financial reporting (as defined in Exchange Act Rules 13a-15(f) and 15d-(f)) for the registrant and have:

    a) Designed such disclosure controls and procedures, or caused such disclosure controls and procedures to be designed under our supervision, to ensure that material information relating to the registrant, including its consolidated subsidiaries, is made known to us by others within those entities, particularly during the period in which this report is being prepared;

    b) Designed such internal control over financial reporting, or caused such internal control over financial reporting to be designed under our supervision, 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;

    c) Evaluated the effectiveness of the registrant's disclosure controls and procedures and presented in this report our conclusions about the effectiveness of the disclosure controls and procedures, as of the end of the period covered by this report based on such evaluation; and

    d) Disclosed in this report any change in the registrant's internal control over financial reporting that occurred during the registrant's most recent fiscal quarter (the registrant's fourth fiscal quarter in the case of an annual report) that has materially affected, or is reasonably likely to materially affect, the registrant's internal control over financial reporting; and

5. The registrant's other certifying officer and I have disclosed, based on our most recent evaluation of internal control over financial reporting, to the registrant's auditors and the audit committee of registrant's board of directors (or persons performing the equivalent functions):

    a) All significant deficiencies and material weaknesses in the design or operation of internal control over financial reporting which are reasonably likely to adversely affect the registrant's ability to record, process, summarize and report financial information; and

    b) Any fraud, whether or not material, that involves management or other employees who have a significant role in the registrant's internal control over financial reporting.

Date: February 28, 2006

/s/ Michael J. Stevens

Michael J. Stevens
Vice President and Chief Financial Officer

Exhibit 32.1

Written Statement of the Chief Executive Officer
Pursuant to 18 U.S.C. Section 1350

Solely for the purposes of complying with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, the undersigned Chairman, President and Chief Executive Officer of Whiting Petroleum Corporation, a Delaware corporation (the "Company"), hereby certify, based on my knowledge, that the Annual Report on Form 10-K of the Company for the fiscal year ended December 31, 2005 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ James J. Volker

James J. Volker
Chairman, President and Chief Executive Officer

Dated: February 28, 2006

Exhibit 32.2

Written Statement of the Chief Financial Officer
Pursuant to 18 U.S.C. Section 1350

Solely for the purposes of complying with 18 U.S.C. Section 1350, as adopted pursuant to Section 906 of the Sarbanes-Oxley Act of 2002, I, the undersigned Vice President of Finance and Chief Financial Officer of Whiting Petroleum Corporation, a Delaware corporation (the "Company"), hereby certify, based on my knowledge, that the Annual Report on Form 10-K of the Company for the fiscal year ended December 31, 2005 (the "Report") fully complies with the requirements of Section 13(a) of the Securities Exchange Act of 1934 and that information contained in the Report fairly presents, in all material respects, the financial condition and results of operations of the Company.

/s/ Michael J. Stevens

Michael J. Stevens
Vice President and Chief Financial Officer

Dated: February 28, 2006