INDEPENDENCE REALTY TRUST, INC
Form 424B3
March 09, 2012

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Filed Pursuant to Rule 424(b)(3)
Registration No. 333-173391

INDEPENDENCE REALTY TRUST, INC.

SUPPLEMENT NO. 3 DATED MARCH 9, 2012

TO THE PROSPECTUS DATED OCTOBER 21, 2011

This document supplements, and should be read in conjunction with, our prospectus dated October 21, 2011, Supplement No. 1 dated October 21, 2011 and Supplement No. 2 dated November 17, 2011, relating to our offering of up to $1,095,000,000 in shares of our common stock. Terms used in this Supplement No. 3 and not otherwise defined herein have the same meanings as set forth in our prospectus. The purpose of this Supplement No. 3 is to disclose:

- the status of our public offering;
- our acquisition of a multifamily property located in Tucson, Arizona;
- the designation, issuance and sale of our Series A preferred stock;
- the authorization of cash distributions to our stockholders;
- an update to the Management section of our prospectus; and
- our Annual Report on Form 10-K for the year ended December 31, 2011.

Status of Our Public Offering

On February 29, 2012, we satisfied the minimum offering amount of our offering as a result of our sale of $3,000,000 in shares of our common stock for $10.00 per share to an indirect wholly owned subsidiary of RAIT Financial Trust (NYSE: RAS), our sponsor, in exchange for cash. We have special escrow provisions for Pennsylvania and Tennessee residents, which have not been satisfied as of March 9, 2012. We will sell shares of our common stock in our public offering until the earlier of June 10, 2013, unless extended, or the date on which the maximum amount has been sold.

Acquisition of the Centrepoint Apartments

On December 16, 2011, we acquired a fee simple interest in the Centrepoint Apartments, a 320-unit apartment community located in Tucson, Arizona, from a wholly owned subsidiary of our sponsor, for $29,500,000, exclusive of closing costs.

The total consideration paid for the Centrepoint Apartments, exclusive of closing costs, consisted of limited partnership units of our operating partnership valued at $11,900,000 and $17,600,000 in cash. On December 16, 2011, our operating partnership issued an additional 38,200 limited partnership units to a wholly owned subsidiary of our sponsor in exchange for $382,000 in cash to fund the closing costs associated with the acquisition. The limited partnership units issued to our sponsor s subsidiary are subject to the same redemption rights as the limited partnership units previously issued in connection with the acquisition of our initial portfolio. We did not pay any compensation or fees to our advisor or its affiliates in connection with the acquisition.

Our board of directors, including a majority of our independent directors, approved the acquisition of the Centrepoint Apartments and issuance of limited partnership units of our operating partnership as being fair and reasonable to us and at a price no greater than the cost of the property to our sponsor. The Centrepoint Apartments were appraised by a nationally recognized appraisal firm that is independent of us and our sponsor, and the selection of the appraiser was approved by our independent directors. The purchase price of the property at the time of acquisition did not exceed its appraised value. The Centrepoint Apartments were acquired by our sponsor on July 23, 2010 as a result of a loan default. To protect its original first mortgage investment, our sponsor took control of the property subject to $29,150,000 of existing indebtedness at the time of acquisition.

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The cash portion of the consideration paid for the Centrepoint Apartments was obtained from the proceeds of a $17,600,000 loan from KeyCorp Real Estate Capital Markets, Inc., or KeyCorp. The loan, which is secured by a first mortgage lien on the Centrepoint Apartments, is non-recourse to us, but we are liable for customary non-recourse carveouts. The loan has a fixed interest rate of 3.71% per annum, a term of 84 months and will mature on January 1, 2019 or any earlier date on which the unpaid principal balance of the loan becomes due and payable by acceleration or otherwise. The loan will be interest-only for the first 36 months of its term and, thereafter, will amortize based on a 30-year schedule. KeyCorp may accelerate the loan upon the occurrence of an event of default, which is defined in the loan agreement. If KeyCorp elects to accelerate upon an event of default, the entire unpaid principal balance of the loan, any accrued interest and any other indebtedness shall immediately become due and payable without any prior notice to us. The loan may be prepaid in full on any scheduled monthly payment date, subject to the payment of a prepayment premium, unless the loan is prepaid in full during the last three months of the loan term, in which event no prepayment premium is due. During the first 78 months of the loan term, the prepayment premium will be an amount equal to the greater of (i) 1.0% of the amount of principal being paid or (ii) the amount calculated using the Fannie Mae yield maintenance prepayment formula set forth in the loan agreement. From the 79th month to the 81st month of the loan term, the prepayment premium will be an amount equal to 1.0% of the amount of principal being repaid.

The Centrepoint Apartments are located on an approximately 17.1 acre site in the north-northwest submarket of Tucson, Arizona, at the Ina Road exit of I-10, eight miles west of downtown Tucson. Interstate I-10 is the major east-west highway that connects Phoenix and Tucson. Ina Road is west Tucson s major retail corridor where the Foothills Mall is located.

The Centrepoint Apartments were constructed in 1995 and benefitted from a capital improvement program from 2006 to 2011. The property is a garden-style, class A apartment community with 23 two-story buildings and 320 units. The unit mix includes 148 one-bedroom, one-bathroom units, 144 two-bedroom, two-bathroom units and 28 three-bedroom, three-bathroom units, with an average unit size of 876 square feet. Unit amenities include a full size washer and dryer, a wood-burning fireplace in select units, walk-in closets and a private patio. Property amenities include a resort-style swimming pool with a sun deck, a fitness facility and a spa. As of the date we acquired Centrepoint Apartments, the occupancy rate of the property was 96%, and the average in-place effective rent was $800 per month. The lease terms are generally consistent with the terms of our other properties.

We believe that the Centrepoint Apartments are suitable for their intended purposes and are adequately covered by insurance. We have not proposed any program for any significant renovation, improvement or development of the Centrepoint Apartments.

Designation, Issuance and Sale of Series A Preferred Stock

On January 3, 2012, we classified 125 shares of our preferred stock as 12.5% Series A cumulative non-voting preferred stock, $0.01 par value per share, which we refer to as Series A preferred stock. On January 4, 2012, we issued and sold all of the shares of the Series A preferred stock in a private offering, which we refer to as the preferred stock offering, for $1,000 per share, or $125,000 in the aggregate, to 125 accredited investors who are not affiliated with us. Customary advisory, set-up and administrative fees and commissions, including approximately $6,250 of brokerage or placement fees, were paid in connection with the preferred stock offering. The preferred stock offering was not registered under the Securities Act, in reliance on the exemption from such registration requirements provided by Section 4(2) of the Securities Act for transactions not involving any public offering and Rule 506 of Regulation D promulgated thereunder. In order to qualify as a REIT, 100 or more persons must own our outstanding shares of capital stock during at least 335 days of a taxable year of 12 months, other than our first REIT taxable year. We expect that the preferred stock offering will ensure that we can meet this requirement. The proceeds from the sale of the Series A preferred stock will be used for general corporate purposes.

Holders of shares of our Series A preferred stock are entitled to receive cumulative preferential cash distributions per unit at a rate of 12.5% per annum, plus accumulated and unpaid dividends thereon, accrued daily and payable semi-annually in arrears on or before June 30 and December 31 of each year. The Series A preferred stock is not convertible into shares of our common stock and has no preemptive or subscription rights. We may redeem shares of the Series A preferred stock, in whole or in part, at any time for a price per share, which we refer to as the redemption price per share, equal to the sum of (i) $1,000, (ii) all accrued and unpaid dividends thereon and

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(iii) if the date of the redemption is on or before December 31, 2013, a redemption premium of $100. Any shares of Series A preferred stock that we redeem will have the status of authorized but unissued and undesignated preferred shares. In addition, upon any liquidation, dissolution or winding up of our company, holders of shares of the Series A preferred stock are entitled to a liquidation preference equal to the redemption price per share. Holders of shares of the Series A preferred stock have no voting rights with respect to any matter except with respect to (a) the authorization or issuance of any equity security senior to or on parity with the Series A preferred stock, (b) any reclassification of the Series A preferred stock and (c) any amendment to our charter that would materially and adversely affect any right, preference, privilege or voting power of the Series A preferred stock or increase the number of shares of authorized Series A preferred stock to a number greater than 125.

In connection with the preferred stock offering, our operating partnership agreement was amended and restated in order to create a series of 125 preferred units of our operating partnership designated as 12.5% Series A preferred units, which we refer to as the Series A preferred units. Pursuant to the amended and restated operating partnership agreement, the Series A preferred units rank senior to all other equity securities issued by our operating partnership and have preferential rights with respect to distributions, liquidation and redemption. At the closing of the preferred stock offering, we contributed the proceeds from the offering to our operating partnership in exchange for 125 Series A preferred units. No selling commission or other consideration was paid in connection with such sale, which was not registered under the Securities Act, in reliance on the exemption from such registration requirements provided by Section 4(2) of the Securities Act for transactions not involving any public offering. The Series A preferred units may be issued only to us as the general partner of our operating partnership. We, as the holder of the Series A preferred units, have the same preferential rights with respect to our operating partnership as holders of shares of the Series A preferred stock have with respect to our company.

Authorization of Cash Distributions

On February 15, 2012, our board of directors authorized and declared distributions on our Series A Preferred Stock for the quarterly period ending on March 31, 2012. The distributions will be payable to the holders of the Series A Preferred Stock of record at a rate of $0.34153005 per day, which is an amount that is equivalent to a 12.5% annualized distribution rate based on a share price of $1,000.00. The distributions will be aggregated and paid in cash on July 29, 2012, pursuant to the requirements of our charter.

On February 15, 2012, our board of directors authorized and declared distributions on our common stock for the months of January, February and March 2012. The distributions will be payable to the holders of our common stock at a rate of $0.00163934 per share per day, which is an amount that is equivalent to a 6.0% annualized distribution rate based on a share price of $10.00. The distributions for each month will be aggregated and paid on or before the fifteenth day following the completion of each respective month. All distributions will be paid in cash or reinvested in stock for those participating in our distribution reinvestment plan.

Update to Management Section

The following disclosure is hereby added to the end of the last paragraph in the Management Committees of Our Board of Directors section of our prospectus.

Our board of directors considers all major decisions concerning our business, including property acquisitions; however, our board may delegate some of its powers to one or more committees. Our charter requires that each committee consist of at least a majority of independent directors. The audit committee, which is the only committee of our board, consists solely of independent directors. Nonetheless, each of our directors owes fiduciary duties to our stockholders that cannot be delegated to one or more of the board s committees.

Annual Report for the Year Ended December 31, 2011

On March 9, 2012, we filed with the SEC our Annual Report on Form 10-K for the year ended December 31, 2011, a copy of which is attached to this Supplement No. 3 as Exhibit A (without exhibits).

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EXHIBIT A

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM 10-K

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

For the fiscal year ended December 31, 2011

or

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

For the Transition Period from to .

Commission file number 333-160093

INDEPENDENCE REALTY TRUST, INC.

(Exact name of registrant as specified in its charter)

Maryland	**26-4567130**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
Cira Centre	
2929 Arch St., 17th Floor	
Philadelphia, PA	**19104**
(Address of principal executive offices)	**(Zip Code)**

(215) 243-9000

(Registrant s telephone number, including area code)

Securities registered pursuant to Section 12(b) of the Securities Exchange Act of 1934:

None

Securities registered pursuant to Section 12(g) of the Securities Exchange Act of 1934:

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 x

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or 15(d) of the Act. Yes ¨ No x

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 x 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 the 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. x

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

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

Large accelerated filer	¨	Accelerated filer	¨
Non-accelerated filer	x (Do not check if a smaller reporting company)	Smaller reporting company	¨

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes ¨ No x

The aggregate market value of the registrant s common stock held by non-affiliates as of June 30, 2011 was $0 because all shares of the registrant s common stock were held by an affiliate on that date.

As of March 9, 2012 there were 320,000 outstanding shares of the Registrant s common stock issued and outstanding.

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INDEPENDENCE REALTY TRUST, INC.

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Special Note Regarding Forward-Looking Statements

Certain statements included in this annual report on Form 10-K (this Annual Report) that are not historical facts (including any statements concerning investment objectives, other plans and objectives of management for future operations or economic performance, or assumptions or forecasts related thereto) are forward-looking statements. These statements are only predictions. We caution that forward-looking statements are not guarantees. Actual events or our investments and results of operations could differ materially from those expressed or implied in any forward-looking statements. Forward-looking statements are typically identified by the use of terms such as may, should, expect, could, intend, plan, anticipate, estimate, believe, continue, predict, potential or the negative of such terms and other comparable terminology.

The forward-looking statements included herein are based upon our current expectations, plans, estimates, assumptions and beliefs, which involve numerous risks and uncertainties. Assumptions relating to the foregoing involve judgments with respect to, among other things, future economic, competitive and market conditions and future business decisions, all of which are difficult or impossible to predict accurately and many of which are beyond our control. Although we believe that the expectations reflected in such forward-looking statements are based on reasonable assumptions, our actual results and performance could differ materially from those set forth in the forward-looking statements. Factors which could have a material adverse effect on our operations and future prospects include, but are not limited to:

- the fact that we have a limited operating history;
- our ability to effectively deploy the proceeds raised in our public offering of common stock;
- changes in economic conditions generally and the real estate market specifically;
- legislative or regulatory changes (including changes to the laws governing the taxation of REITs);
- the availability of capital;
- interest rates; and
- changes to generally accepted accounting principles, or GAAP.

Any of the assumptions underlying the forward-looking statements included herein could be inaccurate, and undue reliance should not be placed on any forward-looking statements included herein. All forward-looking statements are made as of the date this Annual Report is filed with the Securities and Exchange Commission, or the SEC, and the risk that actual results will differ materially from the expectations expressed herein will increase with the passage of time. Except as otherwise required by the federal securities laws, we undertake no obligation to publicly update or revise any forward-looking statements made herein, whether as a result of new information, future events, changed circumstances or any other reason. In light of the significant uncertainties inherent in the forward-looking statements included in this Annual Report, including, without limitation, the risks described under Item 1A Risk Factors, the inclusion of such forward-looking statements should not be regarded as a representation by us or any other person that the objectives and plans set forth in this Annual Report will be achieved.

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PART I

ITEM 1. *Business*

Overview

Independence Realty Trust, Inc., or the Company, was formed on March 26, 2009 as a Maryland corporation that intends to qualify as a real estate investment trust, or REIT, commencing with the taxable year ended December 31, 2011. As used herein, the terms we, our and us refer to the Company and, as required by context, Independence Realty Operating Partnership, LP, or our operating partnership, and their subsidiaries. References to shares and our common stock refer to the shares of our common stock. We intend to invest the net proceeds of our ongoing public offering in a diversified portfolio of multifamily properties with strong and stable cash flows that have the potential to generate attractive distributions for its investors, with a primary focus on core and stabilized multifamily properties that are well leased and produce predictable income. We own substantially all of our assets and conduct our operations through our operating partnership, of which we are the sole general partner.

We sold 20,000 shares of our common stock to Independence Realty Advisors, LLC, or our advisor, on April 30, 2009. Our advisor was purchased on January 20, 2011 by a wholly owned subsidiary of RAIT Financial Trust, or our sponsor, a Maryland REIT whose shares are publicly-traded on the New York Stock Exchange under the symbol RAS. As of December 31, 2011, our sponsor indirectly owned all of our outstanding common stock.

On May 14, 2010, our Registration Statement on Form S-11 (File No. 333-160093) for an offering of a minimum of 250,000 shares and a maximum of 100,000,000 shares of common stock for sale to the public at a price of $10.00 per share, which we refer to as our previous offering, was declared effective by the SEC. On April 8, 2011, we filed a new Registration Statement on Form S-11 (File No. 333-173391) for an offering of a minimum of 250,000 shares and a maximum of 100,000,000 shares of common stock for sale to the public at a price of $10.00 per share (subject to certain discounts) in the primary offering and $9.50 per share pursuant to our distribution reinvestment plan, which we refer to collectively as our offering. Upon the SEC s declaration of effectiveness of our offering on June 10, 2011, our previous offering was automatically terminated. As of December 31, no shares had been sold in our offering or our previous offering.

Subject to certain restrictions and limitations, our business is externally managed on a day-to-day basis by our advisor, a wholly owned subsidiary of our sponsor, pursuant to an advisory agreement between us and our advisor. Our advisor conducts our operations and manages our portfolio of real estate investments. We have no paid employees.

We have retained Independence Realty Securities, LLC, or our dealer manager, a wholly owned subsidiary of our sponsor, to serve as our dealer manager for our offering and assume responsibility for marketing our common shares. Our advisor and our dealer manager will receive compensation and fees for services related to our offering and for the investment and management of our assets.

As of December 31, 2011, we owned seven multifamily properties with 1,812 units located in five states, with a total cost of $137.4 million. See Our Real Estate Portfolio below for detailed information.

Our principal executive offices are located at Cira Centre, 2929 Arch Street, 17th Floor, Philadelphia, Pennsylvania 19104, our telephone number is (215) 243-9000, and our website address is *www.irtreit.com*. The contents of that website are not incorporated by reference or otherwise made part of this Annual Report.

Investment Objectives and Strategy

Our primary investment objectives are to:

- pay attractive and consistent cash distributions;
- preserve invested capital; and

provide a diversified direct investment in multifamily properties.

We intend to acquire a diverse portfolio of multifamily properties located in the United States. We plan to diversify our portfolio by size, property location and risk. We intend to allocate approximately 70% of our portfolio to investments in well-located, quality multifamily properties with strong and stable cash flows, typically located in supply constrained sub-markets with relatively high expectations of rent growth. As appropriate, we intend to implement strategies at these properties that we anticipate will create sustainable long-term increases in property value and generate attractive returns for our investors by, among other benefits, generating higher rental revenue and reducing resident turnover. We intend to allocate approximately 30% of our portfolio to investments in properties that require limited capital expenditures, have existing cash flow and offer opportunities for significantly enhanced return, with a primary focus on multifamily properties, but to a lesser extent other alternative asset classes.

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Our board of directors approves all investment decisions involving the acquisitions of properties upon recommendations made by our advisor and in accordance with our investment guidelines.

2011 Highlights

During 2011, we:

- commenced our public offering on June 10, 2011;
- acquired seven multifamily properties totaling 1,812 units and located in five states; and
- began paying monthly distributions on our common stock at a rate equal to a 6.0% annualized distribution rate if paid over the entire calendar year.

Our Real Estate Portfolio

As of December 31, 2011, we owned the seven multifamily properties described below.

Belle Creek. Belle Creek is located in the Northglenn/Thornton submarket of the Denver, Colorado metropolitan statistical area in the city of Henderson. Belle Creek is a garden style, class A apartment community with 156 units in eight three-story buildings. As of December 31, 2011, Belle Creek had a carrying amount of $9.0 million, was 95.4% occupied, and the average effective rent per month was $829.

Centrepoint. Centrepoint is located in the north-northwest submarket of Tucson, Arizona. The property is a garden-style, class A apartment community with 23 two-story buildings and 320 units. As of December 31, 2011, Centrepoint had a carrying amount of $27.3 million, was 93.1% occupied, and the average effective rent per month was $800.

Copper Mill. Copper Mill is located in the Far North Central submarket of the Austin, Texas metropolitan statistical area. Copper Mill is a garden style, class B apartment community with 320 units in 23 two-story buildings. As of December 31, 2011, Copper Mill had a carrying amount of $16.0 million, was 95.8% occupied, and the average effective rent per month was $656.

Crestmont. Crestmont is located in the Marietta submarket of the Atlanta, Georgia metropolitan statistical area. Crestmont is a garden style, class B apartment community with 228 units in 15 two- and three-story buildings. As of December 31, 2011, Crestmont had a carrying amount of $14.9 million, was 93.0% occupied, and the average effective rent per month was $674.

Cumberland Glen. Cumberland Glen is located in the Smyrna submarket of the Atlanta, Georgia metropolitan statistical area. Cumberland Glen is a garden style, class B apartment community with 222 units in 11 three-story buildings. As of December 31, 2011, Cumberland Glen had a carrying amount of $14.9 million, was 92.2% occupied, and the average effective rent per month was $653.

Heritage Trace. Heritage Trace is located in the Newport News submarket of the Norfolk, Virginia metropolitan statistical area. Heritage Trace is a garden style, class B apartment community with 200 units in 13 two-story buildings. As of December 31, 2011, Heritage Trace had a carrying amount of $12.4 million, was 92.7% occupied, and the average effective rent per month was $741.

Tresa at Arrowhead. Tresa is located in the Peoria/Sun City submarket of the Phoenix, Arizona metropolitan statistical area in the city of Glendale. Tresa is a garden style, class A apartment community with 360 units in 37 one- and two-story buildings. As of December 31, 2011, Tresa had a carrying amount of $33.7 million, was 91.4% occupied, and the average effective rent per month was $766.

See Item 2. Properties for further information on our portfolio.

Competition

In attracting and retaining residents to occupy our properties, we compete with numerous other housing alternatives. Our properties compete directly with other rental apartments as well as condominiums and single-family homes that are available for rent or purchase in the sub-markets in which our properties are located. Principal factors of competition include rent or price charged, attractiveness of the location and property and quality and breadth of services and amenities. If our competitors offer leases at rental rates below current market rates, or below the rental rates we currently charge our tenants, we may lose potential tenants and we may be pressured to reduce our rental rates below those we currently charge or to offer more substantial rent abatements, tenant improvements, early termination rights or below-market renewal options in order to retain tenants when our tenants leases expire.

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The number of competitive properties relative to demand in a particular area has a material effect on our ability to lease apartment units at our properties and on the rents we charge. In certain sub-markets there exists an oversupply of single family homes and condominiums and a reduction of households, both of which affect the pricing and occupancy of our rental apartments. Additionally, we compete with other real estate investors, including other multifamily REITs, pension and investment funds, partnerships and investment companies in acquiring, redeveloping and managing multifamily properties. This competition affects our ability to acquire properties and the price that we pay for such acquisitions.

Financing Objectives

We will fund our investments with proceeds from our offering and expect to finance a portion of our investments with debt. We will use debt financing in various forms in an effort to increase the size of our portfolio and potential returns to our stockholders. We expect to use short-term financing in the form of revolving credit facilities and bank warehousing facilities. For longer-term funding, we may utilize financing provided by government agencies, securitization structures, if available, or mortgage financing on any real estate property we acquire.

We intend to focus our investment activities on obtaining a diverse portfolio of properties. Careful use of debt will help us to achieve our diversification goals because we will have more funds available for investment. Except for the limitations in our charter and as described below, there is no limitation on the amount we may borrow for the purchase of any single property. Our charter limits our borrowings to 300% of our net assets (equivalent to 75% of the cost of our net assets) as of the date of any borrowing, unless excess borrowings approved by a majority of our independent directors and disclosed to our stockholders. Nevertheless, we may exceed the foregoing limits if a majority of our independent directors approve each borrowing in excess of our charter limitation and we disclose such borrowing to our stockholders in our immediately subsequent quarterly report with an explanation from our independent directors of the justification for the excess borrowing. We do not intend to exceed the leverage limit in our charter except in the early stages of our development when the costs of our investments are most likely to exceed our net offering proceeds. Our board of directors must review our aggregate borrowings at least quarterly.

After we have acquired a substantial portfolio of diversified investments, we intend to limit our aggregate leverage to 65% of the combined initial purchase price of all of our real estate properties. During the period when we are beginning our operations, we may employ greater leverage in order to more quickly build a diversified portfolio of assets. As of December 31, 2011, our borrowings as a percentage of our undepreciated investments in real estate was 63%.

Regulations

Our investments are subject to various federal, state, and local laws, ordinances, and regulations, including, among other things, zoning regulations, land use controls, environmental controls relating to air and water quality, noise pollution, and indirect environmental impacts such as increased motor vehicle activity. We believe that we have all permits and approvals necessary under current law to operate our investments.

Income Taxes

We intend to elect to be taxed as a REIT under the Internal Revenue Code of 1986, as amended, or the Code, and intend to operate as such beginning with the taxable year ending December 31, 2011. To qualify as a REIT, we must meet certain organizational and operational requirements, including a requirement to distribute at least 90% of our annual REIT taxable income to stockholders (which is computed without regard to the dividends paid deduction or net capital gain and which does not necessarily equal net income as calculated in accordance with GAAP). As a REIT, we generally will not be subject to federal income tax to the extent we distribute qualifying dividends to our stockholders. If we fail to qualify as a REIT in any taxable year after the taxable year in which we initially elect to be taxed as a REIT, we will be subject to federal income tax on our taxable income at regular corporate income tax rates and generally will not be permitted to qualify for treatment as a REIT for federal income tax purposes for the four taxable years following the year during which qualification is lost, unless the Internal Revenue Service grants us relief under certain statutory provisions.

Financial Information About Industry Segments

Our current business consists of owning, managing, operating, leasing, acquiring, developing, investing in, and disposing of real estate assets. We internally evaluate all of our real estate assets as one industry segment, and, accordingly, we do not report segment information.

Available Information

We are subject to the reporting requirements of the Securities Exchange Act of 1934, as amended, or the Exchange Act, and, as a result, file periodic reports, proxy statements and other information with the SEC. Access to copies of our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other filings with the SEC, including amendments to such filings, may be obtained free of charge from our website, *www.irtreit.com*. These filings are available promptly after we file them with, or furnish them to, the SEC. We are not incorporating our website or any information from the website into this Annual Report. The SEC also maintains a website, *www.sec.gov*, that contains our annual reports on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and other filings with the SEC. Access to these filings is free of charge.

ITEM 1A. ***Risk Factors***

Stockholders should carefully consider the following risk factors in conjunction with the other information contained in this report. The risks discussed in this Annual Report could adversely affect our business, operating results, prospects and financial condition. This could cause the value of our stock to decline. The risks and uncertainties described below are not the only ones we face, but do represent those risks and uncertainties that we believe are material to us. Additional risks and uncertainties not presently known to us or that, as of the date of this Annual Report, we deem immaterial may also harm our business.

Investment Risks

Our lack of prior operating history makes it difficult for stockholders to evaluate our likely performance.

We and our advisor are both entities with limited prior operating histories and we may both be unable to successfully operate our businesses or achieve our investment objectives. The past performance of other real estate investment programs sponsored by our sponsor or affiliates of our sponsor may not be indicative of the performance we may achieve. We may not be able to conduct our business as planned or successfully.

We differ from our sponsor in a number of respects, and therefore, the past performance of our sponsor may not be indicative of our future results.

The past performance of our sponsor may not be indicative of our future results and we may not be able to successfully implement our strategies and operate our business. Our business is different in a number of respects from the operations of our sponsor, resulting in returns to our stockholders that vary from those generated by our sponsor.

Currently, our common stock is not listed on an exchange and there is no public trading market for it, therefore it may be difficult for stockholders to sell their stock. If stockholders sell their stock, it may be at a substantial discount.

Our common stock will not be listed on a stock exchange and there is no current public trading market, nor is there any assurance that a public trading market will ever exist, for our stock. In addition, our charter prohibits the ownership of more than 9.8% in the value of the aggregate of the outstanding shares of our stock or more than 9.8% (in value or number of shares, whichever is more restrictive) of any class or series of the outstanding shares of our stock by a single investor, unless exempted by our board of directors, which may inhibit the ability of our stockholders to sell their stock. We have adopted a share repurchase program which limits the number of shares of stock that may be repurchased annually. Our board of directors may also limit, suspend or terminate our share repurchase program at any time. As a result, it may be difficult for stockholders to sell their shares of stock. If stockholders are able to sell their stock, it might be at a substantial discount from the price they paid. Stockholders should consider our stock illiquid and must be prepared to hold their stock for an indefinite period of time.

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Due to the risks involved in the ownership of real estate, there is no guarantee of any return for our stockholders, and stockholders may lose some or all of their investment.

By owning our shares, stockholders will be subjected to the risks associated with the ownership and operation of real estate properties. Our stockholders will be subject to these risks, which include, without limitation:

- changes in the general economic climate;
- changes in local conditions such as an oversupply of space or reduction in demand for real estate;
- changes in interest rates and the availability of financing;
- changes in property level operating expenses due to inflation or otherwise; and
- changes in laws and governmental regulations, including those governing real estate usage, zoning and taxes.

If our assets decrease in value, the value of an investment in our shares will likewise decrease, and stockholders could lose some or all of their investment.

We may suffer from delays in locating suitable investments, which could adversely affect the return for our stockholders.

Our ability to achieve our investment objectives and to make distributions to our stockholders is dependent upon our advisor s performance in the acquisition of, and arranging of financing for, investments, as well as our property manager s performance in the selection of residents and the negotiation of leases. The current market for properties that meet our investment objectives is highly competitive as is the leasing market for such properties. Stockholders will not have the opportunity to evaluate the terms of most of our transactions or other economic or financial data concerning most of our investments. Stockholders must rely entirely on the oversight of our board of directors, the management ability of our advisor and the performance of the property manager. We cannot be sure that our advisor will be successful in obtaining suitable investments on financially attractive terms.

Additionally, pursuant to the Securities Exchange Act of 1934 we may be required to file with the SEC financial statements of properties we acquire. To the extent any required financial statements are not available or cannot be obtained, we will not be able to acquire the investment. As a result, we may be unable to acquire certain properties that otherwise would be a suitable investment. We could suffer delays in our investment acquisitions due to these reporting requirements, which could adversely affect stockholder returns.

The cash distributions stockholders receive may be less frequent or lower in amount than they expect.

Our board of directors will determine the amount and timing of distributions. In making this determination, our directors will consider all relevant factors, including the amount of cash available for distribution, capital expenditure and reserve requirements and general operational requirements. We cannot assure stockholders that sufficient cash will be available to make distributions to them. We may borrow funds, return capital or sell assets to make distributions. We cannot predict the amount of distributions stockholders may receive and we may be unable to pay, maintain or increase distributions over time.

The sufficiency of cash flow to fund future distributions with respect to an increased number of outstanding shares will depend on the pace at which we are able to identify and close on suitable cash-generating real property investments. Because the accrual of offering proceeds may outpace the investment of these funds in real property acquisitions, cash generated from such investments may become insufficient to fund operating expenses and distributions. Also, because we may receive income from rents or interest at various times during our fiscal year, distributions paid may not reflect our income earned in that particular distribution period. The amount of cash available for distributions will be affected by many factors, including without limitation, our ability to acquire properties as offering proceeds become available, the income from those investments and our operating expense levels. Further, if the aggregate amount of our distributions in any given year exceeds our earnings and profits (as determined for U.S. federal income tax purposes), the excess amount will either be (i) a return of capital or (ii) gain from the sale or exchange of property to the extent that a stockholder s tax basis in our common stock equals or is reduced to zero as the result of our current or prior year distributions, in each case for U.S. federal income tax purposes.

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Distributions paid from sources other than our cash flow from operations will result in us having fewer funds available for the acquisition of properties, which may adversely affect our ability to fund future distributions with cash flow from operations and may adversely affect the overall return on an investment.

We may pay distributions from sources other than from our cash flow from operations. If we have not generated sufficient cash flow from our operations and other sources, such as from borrowings, sale of additional securities, advances from our advisor, our advisor s deferral, suspension and/or waiver of its fees and expense reimbursements, to fund distributions, we may use the offering proceeds. Moreover, our board of directors may change this policy, in its sole discretion, at any time. Distributions made from offering proceeds are a return of capital to stockholders upon which we will have used to pay offering and organization expenses in connection with this offering. We have not established any limit on the amount of proceeds from this offering that may be used to fund distributions. If we fund distributions from the proceeds of our offering, we will have less funds available for acquiring properties. Our inability to acquire properties may have a negative effect on our ability to generate sufficient cash flow from operations to pay distributions. As a result, the return stockholders realize may be reduced and investors who invest in us before we commence significant real estate operations or generate significant cash flow may realize a lower rate of return than later investors. Funding distributions from borrowings could restrict the amount we can borrow for investments, which may affect our profitability. Funding distributions with the sale of assets may affect our ability to generate cash flows. Funding distributions from the sale of additional securities could dilute existing stockholders interests in us if we sell shares of our common stock to third-party investors. Payment of distributions from the mentioned sources could restrict our ability to generate sufficient cash flow from operations, affect our profitability and/or affect the distributions payable to stockholders upon a liquidity transaction, any or all of which may have an adverse effect on the value of an investment in our shares. In addition, subsequent investors may experience immediate dilution in their investment because a portion of our net offering proceeds may have been used to fund distributions instead of retained in our company and used to make investments.

The properties we acquire may not produce the cash flow required to meet our REIT minimum distribution requirements, and we may decide to borrow funds to satisfy such requirements, which could adversely affect our overall financial performance.

We may decide to borrow funds in order to meet the REIT minimum distribution requirements even if our management believes that the then prevailing market conditions generally are not favorable for such borrowings or that such borrowings would not be advisable in the absence of such tax considerations. If we borrow money to meet the REIT minimum distribution requirement or for other working capital needs, our expenses will increase, our net income will be reduced by the amount of interest we pay on the money we borrow and we will be obligated to repay the money we borrow from future earnings or by selling assets, any or all of which may decrease future distributions to stockholders.

To qualify as a REIT, we may be forced to forego otherwise attractive opportunities, which may delay or hinder our ability to meet our investment objectives and reduce the overall return on an investment in our shares.

To qualify as a REIT, we must satisfy certain tests on an ongoing basis concerning, among other things, the sources of our income, nature of our assets and the amounts we distribute to our stockholders. We may be required to make distributions to stockholders at times when it would be more advantageous to reinvest cash in our business or when we do not have funds readily available for distribution. Compliance with the REIT requirements may hinder our ability to operate solely on the basis of maximizing profits and value of an investment in our shares.

Risks Related to Our Organization, Structure and Management

We are dependent upon our sponsor, advisor and their affiliates to conduct our operations, and therefore, any adverse changes in the financial health of our sponsor, advisor or their affiliates, or our relationship with any of them, could hinder our operating performance and the return for our stockholders.

We are dependent on our advisor and affiliates to manage our operations and acquire and manage our portfolio of real estate assets. Our advisor will make all decisions with respect to the management of our company. Our advisor will depend upon the fees and other compensation that it will receive from us in connection with the management and sale of our properties to conduct its operations. Any adverse changes in the financial condition of, or our relationship with, our advisor or property manager could hinder their ability to successfully manage our operations and our portfolio of investments.

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The nature of our sponsor s business, and our dependence on our sponsor and advisor, makes us subject to certain risks that we would not ordinarily be subject to based on our targeted investments.

Our sponsor, as part of the operation of its business, provides a comprehensive set of debt financing options to the commercial real estate industry along with fixed income trading and advisory services. Its investments consist of commercial mortgages, mezzanine loans, other loans and preferred equity investments, debt securities issued by real estate companies, subordinated debentures, mortgage-backed securities, collateralized debt obligations, or CDOs, and other real estate-related debt, none of which we intend to acquire as part of our investment strategy. As a result of our dependence on our sponsor and advisor, we are indirectly subject to some of the same investment risks as our advisor, including risk of payment defaults and credit risks in our sponsor s investment portfolio, the illiquidity of longer-term, subordinate and non-traditional loans, risk of loss from our sponsor s subordinated real estate investments such as mezzanine loans and preferred equity interests, exposure to interest rate risk, risks associated with its use of derivatives and hedging instruments and the risk of loss in its commercial mortgage loans from delinquency and foreclosure. We would not be subject to these risks if we were not dependent upon our sponsor and advisor, and therefore stockholders may not be able to avoid these risks.

In addition, our sponsor engages in securitization strategies that seek to match the payment terms, interest rate and maturity dates of its financings with the payment terms, interest rate and maturity dates of its investments. In particular, our sponsor financed the majority of its commercial real estate loan portfolio through two non-recourse loan securitizations which aggregate $1.85 billion of loan capacity. Our sponsor retained all of the most junior debt tranche and all of the preferred equity issued by these securitizations. Our sponsor also financed most of its debt securities portfolio in a series of non-recourse CDOs, which provide long-dated, interest-only, match funded financing to the debt investments. These securitizations typically require that the principal amount of the assets must exceed the principal balance of the related securities issued by them by a certain amount, a practice known as over-collateralization. The securitization terms provide that if delinquencies or losses exceed specified levels, the required levels of over-collateralization may be increased or may be prevented from decreasing. In addition, failure by a securitization entity to satisfy an over-collateralization test typically results in accelerated distributions to the holders of the senior debt securities issued by the securitization entity, and a reduction in payment to the holders of the junior debt tranche and preferred equity of the type our sponsor holds. As a result, our sponsor is in a first-loss position because the rights of the securities it holds are subordinate in right of payment and in liquidation to the rights of senior security holders issued by the securitization entities. In addition, the failure of the securitization financings of our sponsor to meet their performance tests, including these over-collateralization requirements, may reduce our sponsor s net income and its cash flow generated by these securitizations may trigger certain termination provisions in the related collateral management agreements under which our sponsor manages these securitizations and may cause an event of default under the remaining securitizations. This would increase the likelihood of a reduction or elimination of cash flow to our sponsor, upon which we are dependent, and may result in adverse consequences to our operations.

As a public company, our sponsor may be subject to more litigation than a privately held sponsor with a limited number of investors. Any such litigation may distract our management team.

Our sponsor, RAIT Financial Trust, is a public company and, as a result, may be subject to more litigation than a privately held sponsor with a limited number of investors. For example, our sponsor and certain of its executive officers and trustees were named defendants in class action securities lawsuits filed in 2007. The lawsuits alleged, among other things, that certain defendants violated the Securities Act of 1933, as amended, or the Securities Act, and the Exchange Act by making materially false and misleading statements and material omissions in registration statements and prospectuses. The lawsuits were settled by written agreement, which was approved by a federal district court in 2009. The settlement was funded within the limits of our sponsor s directors and officers insurance. Under the terms of the settlement, the lawsuits were dismissed with prejudice and all defendants received a full release of all claims asserted against them. There can be no assurance that our sponsor or any of its officers will not be subject to additional litigation in the future, which may distract our management team from our business.

If our advisor loses or is unable to obtain key personnel, our ability to implement our investment strategies could be hindered, which could adversely affect our ability to make distributions to our stockholders.

Our success depends to a significant degree upon the contributions of certain of our executive officers and other key personnel of our advisor. We cannot guarantee that all, or any, will remain affiliated with us or our advisor. If any of our key personnel were to cease their affiliation with our advisor, our operating results could suffer. Further, we do not intend to maintain key person life insurance that would provide us with proceeds in the event of death or disability of any of our key personnel.

We believe our future success depends upon our advisor s ability to hire and retain highly skilled managerial, operational and marketing personnel. Competition for such personnel is intense, and we cannot assure stockholders that our advisor will be successful in attracting and retaining such skilled personnel. If our advisor loses or is unable to obtain the services of key personnel, our ability to implement our investment strategies could be delayed or hindered, and the value of an investment in our shares may decline.

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Maryland General Corporation Law prohibits certain business combinations, which may make it more difficult for us to be acquired.

Under Maryland General Corporation Law, business combinations between a Maryland corporation and an interested stockholder or an affiliate of an interested stockholder are prohibited for five years after the most recent date on which the interested stockholder becomes an interested stockholder. These business combinations include a merger, consolidation, share exchange, or in circumstances specified in the statute, an asset transfer or issuance or reclassification of equity securities. An interested stockholder is defined as (i) any person who beneficially owns 10% or more of the voting power of the then outstanding voting stock of the corporation; or (ii) an affiliate or associate of the corporation who, at any time within the two-year period prior to the date in question, was the beneficial owner of 10% or more of the voting power of the then outstanding voting stock of the corporation.

A person is not an interested stockholder under the statute if the board of directors approved in advance the transaction by which the person otherwise would have become an interested stockholder. However, in approving a transaction, the board of directors may provide that its approval is subject to compliance, at or after the time of approval, with any terms and conditions determined by the board.

After the expiration of the five-year period described above, any business combination between the Maryland corporation and an interested stockholder must generally be recommended by the board of directors of the corporation and approved by the affirmative vote of at least:

- 80% of the votes entitled to be cast by holders of the then outstanding shares of voting stock of the corporation; and

- two-thirds of the votes entitled to be cast by holders of voting stock of the corporation, other than shares held by the interested stockholder with whom or with whose affiliate the business combination is to be effected, or held by an affiliate or associate of the interested stockholder.

These super-majority vote requirements do not apply if the corporation s common stockholders receive a minimum price, as defined under Maryland General Corporation Law, for their shares in the form of cash or other consideration in the same form as previously paid by the interested stockholder for its shares. Maryland General Corporation Law also permits various exemptions from these provisions, including business combinations that are exempted by the board of directors before the time that the interested stockholder becomes an interested stockholder. The business combination statute may discourage others from trying to acquire control of us and increase the difficulty of consummating any offer.

Stockholders have limited control over changes in our policies and operations.

Our board of directors determines our major policies, including regarding financing, growth, debt capitalization, REIT qualification and distributions. Our board of directors may amend or revise these and other policies without a vote of the stockholders. Our charter sets forth the stockholder voting rights required under the Statement of Policy Regarding Real Estate Investment Trusts, as revised and adopted by the North American Securities Administrators Association on May 7, 2007, or the NASAA REIT Guidelines. Under our charter and the Maryland General Corporation Law, our stockholders generally have a right to vote only on the following matters:

- the election or removal of directors;

- any amendment of our charter, except that our board of directors may amend our charter without stockholder approval to:

    - change the name or other designation or the par value of any class or series of stock and the aggregate par value of our stock;

    - increase or decrease the aggregate number of our shares;

increase or decrease the number of our shares of any class or series of stock that we have the authority to issue; and

effect certain reverse stock splits;

our liquidation and dissolution; and

our being a party to any merger, consolidation, sale or other disposition of substantially all of our assets or similar reorganization.
All other matters are subject to the discretion of our board of directors.

Our authorized but unissued shares of common and preferred stock may prevent a change in our control.

Our charter authorizes us to issue additional authorized but unissued shares of common or preferred stock. In addition, our board of directors may, without stockholder approval, amend our charter to increase the aggregate number of shares of our common stock or the number of shares of stock of any class or series that we have authority to issue and classify or reclassify any unissued shares of common or preferred stock and set the preferences, rights and other terms of the classified or reclassified shares. As a result, our board of directors may establish a series of shares of common or preferred stock that could delay or prevent a transaction or a change in control that might involve a premium price for shares of our common stock or otherwise be in the best interest of our stockholders.

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Because of our holding company structure, we depend on our operating partnership and its subsidiaries for cash flow and we will be structurally subordinated in right of payment to the obligations of our operating partnership and its subsidiaries.

We are a holding company with no business operations of our own. Our only significant asset is and will be the general partnership interests of our operating partnership. We conduct, and intend to conduct, all of our business operations through our operating partnership. Accordingly, our only source of cash to pay our obligations is distributions from our operating partnership and its subsidiaries of their net earnings and cash flows. We cannot assure our stockholders that our operating partnership or its subsidiaries will be able to, or be permitted to, make distributions to us that will enable us to make distributions to our stockholders from cash flows from operations. Each of our operating partnership s subsidiaries is a distinct legal entity and, under certain circumstances, legal and contractual restrictions may limit our ability to obtain cash from such entities. In addition, because we are a holding company, stockholders claims will be structurally subordinated to all existing and future liabilities and obligations of our operating partnership and its subsidiaries. Therefore, in the event of our bankruptcy, liquidation or reorganization, our assets and those of our operating partnership and its subsidiaries will be able to satisfy stockholders claims only after all of our and our operating partnerships and its subsidiaries liabilities and obligations have been paid in full.

Our board of directors may amend or terminate our share repurchase program, which may impact the ability of stockholders to liquidate their investment.

Our share repurchase program includes limitations on participation. In addition, our board of directors has the ability, in its sole discretion, to reject any request for repurchase and to amend, suspend or terminate the program. As a result, the ability of stockholders to participate in and receive liquidity on their investment through this program may be restricted. Stockholders should not rely on our share repurchase program to provide them with liquidity.

Our rights and the rights of our stockholders to recover on claims against our directors are limited, which could reduce our ability and the ability of our stockholders to recover against them if they negligently cause us to incur losses.

Maryland General Corporation Law provides that a director has no liability in such capacity if he performs his duties in good faith, in a manner he reasonably believes to be in our best interests and with the care that an ordinarily prudent person in a like position would use under similar circumstances. A director who performs his or her duties in accordance with the foregoing standards should not be liable to us or any other person for failure to discharge his or her obligations as a director. We are permitted to purchase and maintain insurance or provide similar protection on behalf of any directors, officers, employees and agents, including our advisor and its affiliates, against any liability asserted which was incurred in any such capacity with us or arising out of such status, except as limited by our charter and/or bylaws. This may result in us having to expend significant funds, which will reduce the available cash for distribution to our stockholders.

Our charter prohibits us from indemnifying our directors, our advisor and its affiliates for any loss or liability that they suffer or holding harmless our directors, the advisor and its affiliates for any loss or liability that we suffer unless certain conditions are met.

As a result, our directors and officers will not be liable for monetary damages unless the director or officer actually received an improper benefit or profit in money, property or services, or is adjudged to be liable to us or our stockholders based on a finding that his or her action, or failure to act, was the result of active and deliberate dishonesty and was material to the cause of action adjudicated in the proceeding.

If we internalize our management functions, the percentage of our outstanding common stock owned by our other stockholders could be reduced, and we could incur other significant costs associated with being self-managed.

In the future, our board of directors may consider internalizing the functions performed for us by our advisor by, among other methods, acquiring our advisor s assets. The method by which we could internalize these functions could take many forms. There is no assurance that internalizing our management functions will be beneficial to us and our stockholders. An acquisition of our advisor could also result in dilution of the interests of our stockholders and could reduce earnings per share and funds from operation per share. Additionally, we may not realize the perceived benefits or we may not be able to properly integrate a new staff of managers and employees or we may not be able to effectively replicate the services provided previously by our advisor, property manager or their affiliates. Internalization transactions, including without limitation, transactions involving the acquisition of advisors or property managers affiliated with entity sponsors have also, in some cases, been the subject of litigation. Even if these claims are without merit, we could be forced to spend significant amounts of money defending claims which would reduce the amount of funds available for us to invest in properties or other investments and to pay distributions. All of these factors could have a material adverse effect on our results of operations, financial condition and ability to pay distributions.

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If we do not successfully implement a liquidity transaction, stockholders may have to hold their investment for an indefinite period.

Our charter does not require our board of directors to pursue a transaction providing liquidity to our stockholders. If our board of directors does determine to pursue a liquidity transaction, we would be under no obligation to conclude the process within a set time. If we adopt a plan of liquidation, the timing of the sale of assets will depend on real estate and financial markets, economic conditions in areas in which properties are located, and federal income tax effects on stockholders, that may prevail in the future. We cannot guarantee that we will be able to liquidate our assets. After we adopt a plan of liquidation, we would likely remain in existence until all our investments are liquidated. If we do not pursue a liquidity transaction, or delay such a transaction due to market conditions, stockholders shares may continue to be illiquid and stockholders may, for an indefinite period of time, be unable to convert their shares to cash easily and could suffer losses.

We will not calculate our net asset value per share until not more than 18 months after completion of our offering stage. In addition, the methodologies we will use to calculate net asset value are uncertain. Therefore, stockholders will not be able to determine the net asset value of their shares for a substantial period of time and may not be able to meaningfully compare our net asset value to the net asset value of other non-listed REITs.

We do not intend to calculate the net asset value per share for our shares until not more than 18 months after the completion of our offering stage. We will consider our offering stage complete when we are no longer publicly offering equity securities in a continuous offering, whether through our current offering or any future offerings (excluding offers to sell under our distribution reinvestment program). Thereafter, our advisor, or another firm it chooses for that purpose, will determine the value of our properties and our other assets based on such information as our advisor determines appropriate, which may or may not include independent valuations of our properties and our other assets or of our enterprise as a whole. We will disclose our net asset value and the methodologies we use to calculate our net asset value to stockholders in our filings with the SEC. Therefore, stockholders will not be able to determine the net asset value of their shares on an on-going basis during this offering and for a substantial period of time thereafter. In addition, we may utilize net asset value calculation methodologies which differ from methodologies utilized by other public, non-listed REITs. As a result, a comparison of our net asset value with the net asset value of other public, non-listed REITs may not be meaningful. Therefore, it is important that stockholders carefully consider how our calculation methodologies differ, if at all, from other non-listed REITs.

Our investment objectives and strategies may be changed without stockholder consent.

Except for the investment limitations contained in our charter, which require stockholder consent to amend, we may change our investment objectives and strategies, and our policies with respect to investments, operations, indebtedness, capitalization and distributions, at any time without the consent of our stockholders, which could result in our making investments that are different from, and possibly riskier or more highly leveraged than, the types of investments described in this prospectus. A change in our investment strategy may, among other things, increase our exposure to interest rate risk, default risk and real estate market fluctuations, all of which could materially affect our ability to achieve our investment objectives.

Risks Related to Conflicts of Interest

Our executive officers have interests that may conflict with the interests of stockholders.

Our executive officers are also affiliated with or are executive officers and shareholders of our sponsor. These individuals may have personal and professional interests that conflict with the interests of our stockholders with respect to business decisions affecting us and our operating partnership. As a result, the effect of these conflicts of interest on these individuals may influence their decisions affecting the negotiation and consummation of the transactions whereby we acquire multifamily properties in the future from our sponsor.

We may have assumed unknown liabilities in connection with the acquisition of the multifamily properties contributed by our sponsor.

We acquired seven multifamily properties contributed by our sponsor subject to existing liabilities, some of which may be unknown at the time of contribution. Unknown liabilities might include liabilities for cleanup or remediation of undisclosed environmental conditions, claims of tenants, vendors or other persons dealing with such entities, tax liabilities, and accrued but unpaid liabilities incurred in the ordinary course of business. As part of our acquisition of these properties, our sponsor made limited representations and warranties to us regarding the properties. Because many liabilities may not be identified at the time of contribution, we may have no recourse against our sponsor.

We will face risks relating to financing arrangements with our sponsor for the multifamily properties we acquire from our sponsor that would not be present with third-party financing.

In connection with the acquisition of the multifamily properties we acquire from our sponsor, our sponsor will make financing available to us. Such financing arrangements may involve risks not otherwise present with other methods of financing, including, for example:

- the possibility that our sponsor may sell or securitize our loan agreements with a third party, in which case our loan would become subject to the rights of the assignee or transferee whose interests may not be the same as our sponsor s interests;

- that our sponsor may in the future have interests that are or that become inconsistent with our interests, which may cause us to disagree with our sponsor as to the best course of action with respect to the payment terms, remedies available under and refinancing of the loan and which disagreement may not be resolved to our satisfaction;

- that in the event of our default on the loan, our sponsor may determine to foreclose upon the collateral without pursuing alternative remedies such as renegotiation of loan terms or workouts that a third-party lender might pursue; and

- that our executive officers are also executive officers or employees of our sponsor and would be responsible for negotiating the terms of any loan agreement on our behalf as well as on our sponsor s behalf.

Our sponsor may also make a loan as part of a lending syndicate with third parties, in which case we expect our sponsor would enter into an inter-creditor agreement that will define its rights and priority with respect to the underlying collateral. The third-party lending syndicate may also have interests that differ with our interests as well as the interests of our sponsor.

Our advisor, executive officers and their affiliates may face conflicts of interest and if inadequate time is devoted to our business, our stockholders may be negatively impacted.

We do not have any employees, and as a result, will rely on the employees of our advisor and its affiliates for the day-to-day operation of our business. The employees of our sponsor and its affiliates currently control our sponsor, which owns properties in the markets in which we may seek to invest, and they spend a material amount of time managing these properties and other assets that are unrelated to our business. Each of our executive officers is also an officer or employee of our sponsor and/or its affiliates, and as a result, these individuals owe fiduciary duties to these other entities and their stockholders, members and limited partners. Because our sponsor and its affiliates engage in other business activities, the employees of our sponsor and its affiliates may experience conflicts of interest in allocating their time and resources among our business and these other activities. The amount of time that our advisor and its affiliates spend on our business will vary from time to time and is expected to be more while we are raising money and acquiring properties. During times of intense activity in other programs and ventures, they may devote less time and fewer resources to our business than are necessary or appropriate to manage our business. We expect that as our real estate activities expand, our advisor will attempt to hire additional employees who would devote substantially all of their time to our business. There is no assurance that our advisor will devote adequate time to our business. If our advisor suffers or is distracted by adverse financial or operational problems in connection with its operations unrelated to us, it may allocate less time and resources to our operations. If any of the foregoing events occur, the returns on our investments and our ability to make distributions to stockholders may affect the value of their shares.

Some of these individuals could make substantial profits as a result of investment opportunities allocated to entities other than us. As a result, these individuals could pursue transactions that may not be in our best interest, which could have a material effect on our operations and our stockholders. Our advisor, property manager and their respective affiliates may, in the future, be engaged in other activities that could result in potential conflicts of interest with the services that they will provide to us. In addition, our sponsor may compete with us for the acquisition and/or refinancing of properties.

Our advisor and its affiliates will receive substantial fees from us. These fees could influence our advisor s advice to us, as well as the judgment of the affiliates of our advisor who serve as our officers and directors. Among other matters, the compensation arrangements, which might entitle affiliates of our advisor to disposition fees and other possible fees in connection with its services for the seller, could affect the judgment of our advisor or its affiliates with respect to property acquisitions from, or the making of investments in, other programs sponsored by our sponsor. Therefore, considerations relating to their compensation from other programs could result in decisions that are not in the best interests of our stockholders, which could hurt our income, and as a result, our ability to make distributions to our stockholders and/or a decline in the value of their shares.

Property management services are being provided by an affiliated party, which may impact our sale of properties, and as a result, affect the value of an investment in our shares.

Our property manager is controlled by our sponsor, and is thus subject to an inherent conflict of interest. Specifically, because the property manager will receive significant fees for managing our properties, our advisor may face a conflict of interest when determining whether we should sell properties under circumstances where the property manager would no longer manage the property after the transaction. As a result of this conflict of interest, we may not dispose of properties when it would be in our best interests to do so.

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If we acquire properties from affiliates of our advisor, the price may be higher than we would pay if the transaction was the result of arm s length negotiations.

The prices we pay to affiliates of our advisor for our properties will be equal to the prices paid by them, plus the costs incurred by them relating to the acquisition and financing of the properties, or if the price to us is in excess of such cost, substantial justification for such excess will exist and such excess will be reasonable and consistent with current market conditions as determined by a majority of our independent directors. Substantial justification for a higher price could result from improvements to a property by the affiliate of our advisor or increases in market value of the property during the period of time the property is owned by the affiliate as evidenced by an appraisal of the property. In no event will we acquire property from an affiliate at an amount in excess of its current appraised value as determined by an independent appraiser selected by our independent directors not otherwise interested in the transaction. An appraisal is current if obtained within the prior year. These prices will not be the subject of arm s length negotiations, which could mean that the acquisitions may be on terms less favorable to us than those negotiated in an arm s length transaction. Even though we will use an independent third-party appraiser to determine fair market value when acquiring properties from our advisor and its affiliates, we may pay more for particular properties than we would have in an arm s length transaction, which would reduce our cash available for investment in other properties or distribution to our stockholders.

Payment of fees to our advisor and its affiliates will result in immediate dilution of the value of an investment in our shares and reduce cash available for investment and distribution.

Our advisor and its affiliates will perform services for us in connection with the management and leasing of our properties. They will be paid significant fees for these services, which will result in immediate dilution of the value of an investment in our shares and reduce the amount of cash available for investment and for distribution to stockholders. Compensation to be paid to our advisor may be increased subject to approval by our independent directors and the limitations in our charter, which would further dilute an investment in our shares and reduce the amount of cash available for investment or distribution to stockholders.

The agreements between us and our advisor or its affiliates, and the fees paid to them pursuant to such agreements, were not reached through arm s length negotiations and may not reflect the terms that would be available from a third party; that is, a third party unaffiliated with our advisor may be willing to provide such services to us at a lower price. Substantial up-front fees also increase the risk that our stockholders will not be able to resell their shares of stock at a profit, even if our stock is listed on a national securities exchange. See Compensation Table and Management.

Our advisor and its affiliates receive fees and other compensation based upon our investments, which may impact operating decisions, and as a result, affect the value of an investment in our shares.

Our advisor and its affiliates receive fees and other compensation based on our investments, and are in a position to make decisions about our investments in ways that could maximize fees payable to our advisor and its affiliates. Some compensation is payable to our advisor whether or not there is cash available to make distributions to our stockholders. To the extent this occurs, our advisor and its affiliates benefit from us retaining ownership, and leveraging, our assets, while our stockholders may be better served by the sale or disposition of, or lack of leverage on, the assets. For example, because asset management fees payable to our advisor are based on total assets under management, including assets purchased using debt, our advisor may have an incentive to incur a high level of leverage in order to increase the total amount of assets under management. In addition, our advisor s ability to receive fees and reimbursements depends on our continued investment in real properties. Therefore, the interest of our advisor and its affiliates in receiving fees may conflict with the interest of our stockholders in earning income on their investment in our common stock.

Our advisor may receive substantial fees in connection with the refinancing of any debt that we use to acquire properties or to make other permitted investments, or that is assumed, directly or indirectly, in connection with the acquisition of properties.

In connection with any refinancing of our debt that we use to acquire properties or to make other permitted investments, including any indebtedness assumed by us in connection with the acquisition of properties, we will pay our advisor a financing coordination fee equal to 1% of the amount available and/or outstanding under such financing, subject to certain limitations. There is no limit on our ability to refinance our indebtedness. As a result, our advisor has an incentive to recommend that we refinance our existing indebtedness, regardless of whether the structure, terms or conditions are favorable to us given our then-existing debt levels and current market conditions. Although our charter limits the amount of indebtedness that we may incur, our advisor may have an incentive to recommend that we refinance our indebtedness and incur additional indebtedness in connection with such refinancing.

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We may compete with other entities affiliated with our sponsor for tenants.

Our sponsor and its affiliates are not prohibited from engaging, directly or indirectly, in any other business or from possessing interests in any other business ventures, including ventures involved in the acquisition, development, ownership, management, leasing or sale of real estate. Our sponsor and/or its affiliates may own and/or manage properties in the same geographical areas in which we expect to acquire real estate assets. Therefore, our properties may compete for tenants with other properties owned and/or managed by our sponsor and its affiliates. Our sponsor may face conflicts of interest when evaluating tenant opportunities for our properties and other properties owned and/or managed by our sponsor and its affiliates, and these conflicts of interest may have a negative impact on our ability to attract and retain tenants.

If we invest in joint ventures, the objectives of our partners may conflict with our objectives.

In accordance with our acquisition strategies, we may make investments in joint ventures or other partnership arrangements between us and affiliates of our sponsor or with unaffiliated third parties. Investments in joint ventures which own real properties may involve risks otherwise not present when we purchase real properties directly. For example, our co-venturer may file for bankruptcy protection, have economic or business interests or goals which are inconsistent with our interests or goals, or take actions contrary to our instructions, requests, policies or objectives. Among other things, actions by a co-venturer might subject real properties owned by the joint venture to liabilities greater than those contemplated by the terms of the joint venture or other adverse consequences.

These diverging interests could result in, among other things, exposing us to liabilities of the joint venture in excess of our proportionate share of these liabilities. The partition rights of each owner in a jointly owned property could reduce the value of each portion of the divided property. Moreover, there is an additional risk that the co-venturers may not be able to agree on matters relating to the property they jointly own. In addition, the fiduciary obligation that our sponsor or our board of directors may owe to our partner in an affiliated transaction may make it more difficult for us to enforce our rights.

General Risks Related to Investments in Real Estate

Economic conditions may adversely affect the residential real estate market and our income.

A residential property s income and value may be adversely affected by international, national and regional economic conditions. Currently, the U.S. and international markets are experiencing increased levels of volatility due to a combination of many factors, including decreasing values of home prices and commercial real estate, limited access to credit markets, increased energy costs, increased unemployment rates, and a national and global recession. If such conditions persist, the residential real estate industry may experience a significant decline in business caused by a reduction in overall renters. Continued adverse economic conditions may also have an adverse affect on our operations if the tenants occupying the residential properties we acquire cease making rent payments to us.

In addition, local real estate conditions such as an oversupply of properties or a reduction in demand for properties, availability of for sale properties, competition from other similar properties, our ability to provide adequate maintenance, insurance and management services, increased operating costs (including real estate taxes), the attractiveness and location of the property and changes in market rental rates, may adversely affect a property s income and value. The continued rise in energy costs could result in higher operating costs, which may affect our results from operations. In addition, local conditions in the markets in which we own or intend to own properties may significantly affect occupancy or rental rates at such properties. The risks that may adversely affect conditions in those markets include: layoffs, plant closings, relocations of significant local employers and other events negatively impacting local employment rates and the local economy; an oversupply of, or a lack of demand for, apartments; a decline in household formation; the inability or unwillingness of residents to pay rent increases; and rent control, rent stabilization and other housing laws, which could prevent us from raising rents.

Rising expenses could reduce cash flow and funds available for future acquisitions, which may have a material affect on the value of an investment in our shares.

Our properties will be subject to increases in tax rates, utility costs, operating expenses, insurance costs, repairs and maintenance, administrative and other expenses. Some of the leases on our properties may require the tenants to pay all or a portion of the expenses; however, renewals of leases or future leases may not be negotiated on that basis, in which event we will have to pay those expenses. Such increased expenses could adversely affect funds available for future acquisitions or cash available for distributions.

Failure to generate sufficient cash flows from operations may reduce distributions to stockholders.

We intend to rely primarily on our cash flow from operations to make distributions to our stockholders. The cash flow from equity investments in our multifamily properties depends on the amount of revenue generated and expenses incurred in operating our properties. The revenue generated and expenses incurred in operating our properties depends on many factors, some of which are beyond our control. For instance, rents from our properties may not increase as expected. If our properties do not generate revenue sufficient to meet our operating expenses, debt service and capital expenditures, our cash flows and ability to make distributions to stockholders will be adversely affected.

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If we purchase assets at a time when the residential real estate market is experiencing substantial influxes of capital investment and competition for properties, the real estate we purchase may not appreciate or may decrease in value.

The residential real estate market may experience substantial influxes of capital from investors. This substantial flow of capital, combined with significant competition for real estate, may result in inflated purchase prices for such assets. To the extent we purchase real estate in such an environment, we are subject to the risk that, if the real estate market subsequently ceases to attract the same level of capital investment, or if the number of companies seeking to acquire such assets decreases, our returns will be lower and the value of our assets may not appreciate or may decrease significantly below the amount we paid for such assets.

We may not make a profit if we sell a property, which could adversely impact our ability to make cash distributions to our stockholders.

The prices that we can obtain when we determine to sell a property will depend on many factors that are presently unknown, including the operating history, tax treatment of real estate investments, demographic trends in the area and available financing. There is a risk that we will not realize any significant appreciation on our investment in a property. Accordingly, the ability of our stockholders to recover all or any portion of their investment under such circumstances will depend on the amount of funds so realized and claims to be satisfied therefrom.

Our properties may not be diversified by geographic location or by type, which may increase the risk of an investment in our shares.

If we are unable to diversify our investments by region, our performance will be linked to a greater extent to economic conditions in the regions in which we acquire properties. Therefore, to the extent that there are adverse economic conditions in the regions in which our properties are located and in the market for real estate properties, such conditions could result in a reduction of our income, and thus affect the amount of distributions we can make to our stockholders. Further, we do not anticipate diversifying our investments in properties by industry, that is, we plan to invest primarily in the multifamily industry. Therefore, a downturn in such industry will likely have a more pronounced effect on the amount of cash available to us for distribution or on the value of our assets than if we had diversified our investments by property type.

We may incur liabilities in connection with properties we acquire.

Our anticipated acquisition activities are subject to many risks. We may acquire properties that are subject to liabilities or that have problems relating to environmental condition, state of title, physical condition or compliance with zoning laws, building codes, or other legal requirements. In each case, our acquisition may be without any, or with only limited, recourse with respect to unknown liabilities or conditions. As a result, if any liability were asserted against us relating to those properties or entities, or if any adverse condition existed with respect to the properties or entities, we might have to pay substantial sums to settle or cure it, which could adversely affect our cash flow and operating results. However, some of these liabilities may be covered by insurance. In addition, as mentioned above, absent a determination that an expedited acquisition is necessary, we intend to perform customary due diligence regarding each property or entity we acquire. We also will attempt to obtain appropriate representations and undertakings from the sellers of the properties or entities we acquire, although it is possible that the sellers may not have the resources to satisfy their indemnification obligations if a liability arises. Unknown liabilities to third parties with respect to properties or entities acquired might include, without limitation:

- liabilities for clean-up of undisclosed environmental contamination;
- claims by tenants or other persons dealing with the former owners of the properties;
- liabilities incurred in the ordinary course of business; and
- claims for indemnification by general partners, directors, officers and others indemnified by the former owners of the properties.

We may suffer losses that are not covered by insurance.

If we suffer losses that are not covered by insurance or that are in excess of insurance coverage, we could lose invested capital and anticipated profits. We intend to cause comprehensive insurance to be obtained for our properties, including casualty, liability, fire, extended coverage and rental loss customarily obtained for similar properties in amounts which our advisor determines are sufficient to cover reasonably foreseeable losses, and with policy specifications and insured limits that we believe are adequate and appropriate under the circumstances. Material losses may occur in excess of insurance proceeds with respect to any property as insurance proceeds may not provide sufficient resources to fund the losses. However, there are types of losses, generally of a catastrophic nature, such as losses due to wars, earthquakes, floods, hurricanes, pollution, environmental matters, mold or terrorism which are either uninsurable or not economically insurable, or may be insured subject to limitations, such as large deductibles or co-payments.

Insurance companies have recently begun to exclude acts of terrorism from standard coverage. Terrorism insurance is currently available at an increased premium, and it is possible that the premium will increase in the future or that terrorism coverage will become unavailable. In some cases, mortgage lenders have begun to insist that specific coverage against terrorism be purchased by owners as a condition for providing loans. We intend to obtain terrorism insurance if required by our lenders, but the terrorism insurance that we obtain may not be sufficient to cover loss for damages to our properties as a result of terrorist attacks. In addition, we may not be able to obtain insurance against the risk of terrorism because it may not be available or may not be available on terms that are economically feasible. In such instances, we may be required to provide other financial support, either through financial assurances or self-insurance, to cover potential losses. We cannot assure our stockholders that we will have adequate coverage for such losses.

In addition, many insurance carriers are excluding asbestos-related claims from standard policies, pricing asbestos endorsements at prohibitively high rates or adding significant restrictions to such coverage.

Because of our inability to obtain specialized coverage at rates that correspond to our perceived level of risk, we may not obtain insurance for acts of terrorism or asbestos-related claims. We will continue to evaluate the availability and cost of additional insurance coverage from the insurance market. If we decide in the future to purchase insurance for terrorism or asbestos, the cost could have a negative impact on our results of operations. If an uninsured loss or a loss in excess of insured limits occurs on a property, we could lose our capital invested in the property, as well as the anticipated future revenues from the property and, in the case of debt that is recourse to us, would remain obligated for any mortgage debt or other financial obligations related to the property. Any loss of this nature would adversely affect us. Although we intend to adequately insure our properties, we cannot assure that we will successfully do so.

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We may be unable to secure funds for future capital improvements, which could adversely impact our ability to make cash distributions to our stockholders.

When residents do not renew their leases or otherwise vacate their space, in order to attract replacement residents, we may be required to expend funds for capital improvements to the vacated apartment units. In addition, we may require substantial funds to renovate a multifamily community in order to sell it, upgrade it or reposition it in the market. If we have insufficient capital reserves, we will have to obtain financing from other sources. We intend to establish capital reserves in an amount we, in our discretion, believe is necessary. A lender also may require escrow of capital reserves in excess of any established reserves. If these reserves or any reserves otherwise established are designated for other uses or are insufficient to meet our cash needs, we may have to obtain financing from either affiliated or unaffiliated sources to fund our cash requirements. We cannot assure our stockholders that sufficient financing will be available or, if available, will be available on economically feasible terms or on terms acceptable to us. Moreover, certain reserves required by lenders may be designated for specific uses and may not be available for capital purposes such as future capital improvements. Additional borrowing will increase our interest expense, therefore, our financial condition and our ability to make cash distributions to our stockholders may be adversely affected.

Short-term leases expose us to the effects of declining market rent, which could adversely impact our ability to make cash distributions to our stockholders.

We expect that most of our leases will be for a term of one year or less. Because these leases generally permit the residents to leave at the end of the lease term without any penalty, our rental revenues may be impacted by declines in market rents more quickly than if our leases were for longer terms.

The profitability of our acquisitions is uncertain.

We intend to acquire properties selectively. Acquisition of properties entails risks that investments will fail to perform in accordance with expectations. In undertaking these acquisitions, we will incur certain risks, including the expenditure of funds on, and the devotion of management s time to, transactions that may not come to fruition. Additional risks inherent in acquisitions include risks that the properties will not achieve anticipated occupancy levels and that estimates of the costs of improvements to bring an acquired property up to standards established for the market position intended for that property may prove inaccurate.

We will face competition from third parties, including other multifamily communities, which may limit our profitability and the return for our stockholders.

The residential multifamily industry is highly competitive. This competition could reduce occupancy levels and revenues at our multifamily properties, which would adversely affect our operations. We compete with many other entities engaged in real estate investment activities, including individuals, corporations, bank and insurance company investment accounts, other REITs, real estate limited partnerships, and other entities engaged in real estate investment activities. Many of these entities have significant financial and other resources, including operating experience, allowing them to compete effectively with us. Competitors with substantially greater financial resources than us may be able to accept more risk than we can effectively manage. In addition, those competitors that are not REITs may be at an advantage to the extent they can utilize working capital to finance projects, while we (and our competitors that are REITs) will be required by the annual distribution provisions under the Code to distribute significant amounts of cash from operations to our stockholders. Our competitors include those in other apartment communities both in the immediate vicinity where our multifamily properties will be located and the broader geographic market. Such competition may also result in overbuilding of multifamily communities, causing an increase in the number of apartment units available and potentially decreasing our occupancy and apartment rental rates. We may also be required to expend substantial sums to attract new residents. The resale value of the property could be diminished because the market value of a particular property will depend principally upon the value of the leases of such property. In addition, increases in operating costs due to inflation may not be offset by increased apartment rental rates. Further, costs associated with real estate investment, such as real estate taxes and maintenance costs, generally are not reduced when circumstances cause a reduction in income from the investment. These events would cause a significant decrease in revenues and could cause us to reduce the amount of distributions to our stockholders.

The large quantity of foreclosed homes and low residential mortgage rates may result in potential renters purchasing residences rather than leasing them, and as a result, cause a decline in occupancy rates.

The large quantity of foreclosed homes, along with the low residential mortgage interest rates currently available and government sponsored programs to promote home ownership, has resulted in a record high level on the National Association of Realtor s Housing Affordability Index, an index used to measure whether or not a typical family could qualify for a mortgage loan on a typical home. The foregoing factors may encourage potential renters to purchase residences rather than lease them, thereby causing a decline in the occupancy rates of our properties.

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Failure to succeed in new markets or in new property classes may have adverse consequences on our performance.

We may make acquisitions outside of our existing market areas or the property classes of our primary focus if appropriate opportunities arise. Our sponsor s, advisor s or any of our affiliates historical experience in their existing markets in owning and operating certain classes of property does not ensure that we will be able to operate successfully in new markets, should we choose to enter them, or that we will be successful in new property classes. We may be exposed to a variety of risks if we choose to enter new markets, including an inability to accurately evaluate local market conditions, to identify appropriate acquisition opportunities, to hire and retain key personnel, and a lack of familiarity with local governmental and permitting procedures. In addition, we may abandon opportunities to enter new markets or acquire new classes of property that we have begun to explore for any reason and may, as a result, fail to recover expenses already incurred.

Acquiring or attempting to acquire multiple properties in a single transaction may adversely affect our operations.

We are likely to acquire multiple properties in a single transaction. Such portfolio acquisitions are more complex and expensive than single-property acquisitions, and the risk that a multiple-property acquisition does not close may be greater than in a single-property acquisition. Portfolio acquisitions may also result in us owning investments in geographically dispersed markets, placing additional demands on our ability to manage the properties in the portfolio. In addition, a seller may require that a group of properties be purchased as a package even though we may not want to purchase one or more properties in the portfolio. In these situations, if we are unable to identify another person or entity to acquire the unwanted properties, we may be required to operate, or attempt to dispose of, these properties. To acquire multiple properties in a single transaction we may be required to accumulate a large amount of cash. We expect the returns that we can earn on such cash to be less than the ultimate returns on real property, and therefore, accumulating such cash could reduce the funds available for distributions. Any of the foregoing events may have an adverse effect on our operations.

If we sell properties by providing financing to purchasers, we will bear the risk of default by the purchaser.

If we decide to sell any of our properties, we intend to use our commercially reasonable efforts to sell them for cash. However, in some instances we may sell our properties by providing financing to purchasers. If we provide financing to purchasers, we will bear the risk of default by the purchaser and will be subject to remedies provided by law, which could negatively impact distributions to our stockholders. There are no limitations or restrictions on our ability to take such purchase money obligations. We may, therefore, take a purchase money obligation secured by a mortgage as full or partial payment for the purchase price of a property. The terms of payment to us generally will be affected by custom in the area where the property being sold is located and the then-prevailing economic conditions. If we receive promissory notes or other property in lieu of cash from property sales, the distribution of the proceeds of sales to our stockholders, or their reinvestment in other assets, will be delayed until the promissory notes or other property are actually paid, sold or refinanced or we have otherwise disposed of such promissory notes or other property. In some cases, we may receive initial down payments in cash and other property in the year of sale in an amount less than the selling price and subsequent payments will be spread over a number of years. If any purchaser defaults under a financing arrangement with us, it could negatively impact our ability to make distributions to our stockholders.

Our revenue and net income may vary significantly from one period to another due to investments in opportunity-oriented properties and portfolio acquisitions, which could increase the variability of our cash available for distributions.

We may make investments in opportunity-oriented properties in various phases of development, redevelopment or repositioning and portfolio acquisitions, which may cause our revenues and net income to fluctuate significantly from one period to another. Projects do not produce revenue while in development or redevelopment. During any period when our projects in development or redevelopment or those with significant capital requirements increase without a corresponding increase in stable revenue-producing properties, our revenues and net income will likely decrease. Many factors may have a negative impact on the level of revenues or net income produced by our portfolio of investments, including higher than expected construction costs, failure to complete projects on a timely basis, failure of the properties to perform at expected levels upon completion of development or redevelopment, and increased borrowings necessary to fund higher than expected construction or other costs related to the project. Further, our net income and stockholders equity could be negatively affected during periods with large portfolio acquisitions, which generally require large cash outlays and may require the incurrence of additional financing. Any such reduction in our revenues and net income during such periods could cause a resulting decrease in our cash available for distributions during the same periods.

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We may have difficulty selling real estate investments, and our ability to distribute all or a portion of the net proceeds from such sale to our stockholders may be limited.

Real estate investments are relatively illiquid, and as a result, we will have a limited ability to vary our portfolio in response to changes in economic or other conditions. We will also have a limited ability to sell assets in order to fund working capital and similar capital needs. When we sell any of our properties, we may not realize a gain on such sale. We may elect not to distribute any proceeds from the sale of properties to our stockholders; for example, we may use such proceeds to:

- purchase additional properties;
- repay debt, if any;
- buy out interests of any co-venturers or other partners in any joint venture in which we are a party;
- create working capital reserves; or
- make repairs, maintenance, tenant improvements or other capital improvements or expenditures to our remaining properties.

Our ability to sell our properties may also be limited by our need to avoid a 100% penalty tax that is imposed on gain recognized by a REIT from the sale of property characterized as dealer property. In order to ensure that we avoid such characterization, we may be required to hold our properties for a minimum period of time and comply with certain other requirements in the Code.

We may acquire properties with lock-out provisions, or agree to such provisions in connection with obtaining financing, which may prohibit us from selling a property, or may require us to maintain specified debt levels for a period of years on some properties.

We may acquire properties in exchange for operating partnership units and agree to restrictions on sales or refinancing, called lock-out provisions, that are intended to preserve favorable tax treatment for the owners of such properties who sell them to us. Additionally, we may agree to lock-out provisions in connection with obtaining financing for the acquisition of properties. Lock-out provisions could materially restrict us from selling, otherwise disposing of or refinancing properties. This would affect our ability to turn our investments into cash and thus affect cash available to return capital to our stockholders. Lock-out provisions could impair our ability to take actions during the lock-out period that would otherwise be in the best interests of our stockholders, and therefore, might have an adverse impact on the value of the shares, relative to the value that would result if the lock-out provisions did not exist. In particular, lock-out provisions could preclude us from participating in major transactions that could result in a disposition of our assets or a change in control even though that disposition or change in control might be in the best interests of our stockholders.

Actions of our joint venture partners could subject us to liabilities in excess of those contemplated or prevent us from taking actions which are in the best interests of our stockholders, which could result in lower investment returns to our stockholders.

We may enter into joint ventures with affiliates and other third parties to acquire or improve properties. We may also purchase properties in partnerships, co-tenancies or other co-ownership arrangements. Such investments may involve risks not otherwise present when acquiring real estate directly, including, for example:

- joint venturers may share certain approval rights over major decisions;
- a co-venturer, co-owner or partner may at any time have economic or business interests or goals which are or which become inconsistent with our business interests or goals, including inconsistent goals relating to the sale of properties held in the joint

venture or the timing of termination or liquidation of the joint venture;

the possibility that our co-venturer, co-owner or partner in an investment might become insolvent or bankrupt;

the possibility that we may incur liabilities as a result of an action taken by our co-venturer, co-owner or partner;

that such co-venturer, co-owner or partner may be in a position to take action contrary to our instructions or requests or contrary to our policies or objectives, including our policy with respect to qualifying and maintaining our qualification as a REIT;

disputes between us and our joint venturers may result in litigation or arbitration that would increase our expenses and prevent our officers and directors from focusing their time and effort on our business and result in subjecting the properties owned by the applicable joint venture to additional risk; or

that under certain joint venture arrangements, neither venture partner may have the power to control the venture, and an impasse could be reached which might have a negative influence on the joint venture.

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These events might subject us to liabilities in excess of those contemplated and thus reduce the return on an investment in our shares. If we have a right of first refusal or buy/sell right to buy out a co-venturer, co-owner or partner, we may be unable to finance such a buy-out if it becomes exercisable or we may be required to purchase such interest at a time when it would not otherwise be in our best interest to do so. If our interest is subject to a buy/sell right, we may not have sufficient cash, available borrowing capacity or other capital resources to allow us to elect to purchase an interest of a co-venturer subject to the buy/sell right, in which case we may be forced to sell our interest as the result of the exercise of such right when we would otherwise prefer to keep our interest. Finally, we may not be able to sell our interest in a joint venture if we desire to exit the venture.

Risks Associated with Debt Financing

We plan to incur mortgage indebtedness and other borrowings, which may increase our business risks.

We intend to acquire properties subject to existing financing or by borrowing new funds. In addition, we intend to incur or increase our mortgage debt by obtaining loans secured by selected, or all of our, real properties to obtain funds to acquire additional real properties and/or make capital improvements to properties. We may also borrow funds, if necessary, to satisfy the requirement that we generally distribute to stockholders as dividends at least 90% of our annual REIT taxable income (excluding net capital gain), or otherwise as is necessary or advisable to assure that we maintain our qualification as a REIT for U.S. federal income tax purposes.

We intend to incur mortgage debt on a particular property if we believe the property s projected cash flow is sufficient to service the mortgage debt. However, if there is a shortfall in cash flow requiring us to use cash from other sources to make the mortgage payments on the property, then the amount available for distributions to stockholders may be affected. In addition, incurring mortgage debt increases the risk of loss since defaults on indebtedness secured by properties may result in foreclosure actions initiated by lenders and our loss of the property securing the loan which is in default. For tax purposes, a foreclosure of any of our properties would be treated as a sale of the property for a purchase price equal to the outstanding balance of the debt secured by the mortgage. If the outstanding balance of the debt secured by the mortgage exceeds our tax basis in the property, we would recognize taxable income on foreclosure, but would not receive any cash proceeds. We may, in some circumstances, give a guaranty on behalf of an entity that owns one or more of our properties. In these cases, we will be responsible to the lender for satisfaction of the debt if it is not paid by such entity. If any mortgages contain cross-collateralization or cross-default provisions, there is a risk that more than one real property may be affected by a default.

Any mortgage debt which we place on properties may contain clauses providing for prepayment penalties. If a lender invokes these penalties upon the sale of a property or the prepayment of a mortgage on a property, the cost to us to sell the property could increase substantially, and may even be prohibitive. This could lead to a reduction in our income, which would reduce cash available for distribution to stockholders and may prevent us from borrowing more money.

We may also finance our property acquisitions using interest-only mortgage indebtedness. During the interest-only period, the amount of each scheduled payment will be less than that of a traditional amortizing mortgage loan. The principal balance of the mortgage loan will not be reduced (except in the case of prepayments) because there are no scheduled monthly payments of principal during this period. After the interest-only period, we will be required either to make scheduled payments of amortized principal and interest or to make a lump-sum or balloon payment at maturity. These required principal or balloon payments will increase the amount of our scheduled payments and may increase our risk of default under the related mortgage loan. If the mortgage loan has an adjustable interest rate, the amount of our scheduled payments also may increase at a time of rising interest rates. Increased payments and substantial principal or balloon maturity payments will reduce the funds available for distribution to our stockholders because cash otherwise available for distribution will be required to pay principal and interest associated with these mortgage loans.

There is no limitation on the amount we may invest in any single property or other asset or, subject to the limitations in our charter, on the amount we can borrow for the purchase of any individual property or other investment. Under our charter, the maximum amount of our secured and unsecured borrowings in relation to net assets cannot exceed 300% of net assets (the equivalent of 75% of the cost of our net assets) on the date of any borrowing in the absence of a satisfactory showing that a higher level of borrowing is appropriate, approval by a majority of independent directors and disclosure to our stockholders. Net assets means our total assets, other than intangibles, at cost before deducting depreciation, reserves for bad debts or other non-cash reserves less our total liabilities, calculated at least quarterly on a basis consistently applied. This restriction does not, however, apply to individual properties, and therefore, does not limit our ability to borrow more than 75% of the contract purchase price for any individual property.

If mortgage debt is unavailable at reasonable rates, we may not be able to finance the properties, which could reduce the number of properties we can acquire and the amount of cash distributions we can make.

When we place mortgage debt on properties, we run the risk of being unable to refinance the properties when the loans come due, or of being unable to refinance on favorable terms. If interest rates are higher when the properties are refinanced, we may not be able to finance the properties at reasonable rates and our income could be reduced. If this occurs, it would reduce cash available for distribution to our stockholders, and it may prevent us from borrowing more money.

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Our ability to obtain financing on reasonable terms could be impacted by negative capital market conditions.

Recently, domestic financial markets have experienced unusual volatility, uncertainty and a tightening of liquidity in both the investment grade debt and equity capital markets. The commercial real estate debt markets are also experiencing volatility as a result of certain factors including the tightening of underwriting standards by lenders and credit rating agencies and the restricted Collateralized Mortgage Backed Securities market. Credit spreads for major sources of capital have widened significantly as investors have demanded a higher risk premium. This is resulting in lenders increasing the cost for debt financing. Should the overall cost of borrowings increase, either by increases in the index rates or by increases in lender spreads, we will need to factor such increases into the economics of our acquisitions. This may result in our acquisitions generating lower overall economic returns and potentially reducing cash flow available for distribution.

The recent dislocations in the debt markets have reduced the amount of capital that is available to finance real estate, which, in turn, (a) will no longer allow real estate investors to rely on capitalization rate compression to generate returns and (b) has slowed real estate transaction activity, all of which may reasonably be expected to have a material impact on revenues and income from the acquisition and operations of real properties and mortgage loans. Investors will need to focus on market-specific growth dynamics, operating performance, asset management and the long-term quality of the underlying real estate asset.

In addition, the state of the debt markets could have an impact on the overall amount of capital investing in real estate which may result in price or value decreases of real estate assets.

Consequently, there is greater uncertainty regarding our ability to access the credit market in order to attract financing on reasonable terms. Investment returns on our assets and our ability to make acquisitions could be adversely affected by our inability to secure financing on reasonable terms, if at all.

The return on an investment in our shares may be reduced if we are required to register as an investment company under the Investment Company Act.

We are not registered, and do not intend to register our company or any of our subsidiaries, as an investment company under the Investment Company Act. If we become obligated to register the company or any of our subsidiaries as an investment company, the registered entity would have to comply with a variety of substantive requirements under the Investment Company Act imposing, among other things, limitations on capital structure, restrictions on specified investments, prohibitions on transactions with affiliates and compliance with reporting, record keeping, voting, proxy disclosure and other rules and regulations that would significantly change our operations.

We intend to conduct our operations, directly and through wholly or majority-owned subsidiaries, so that we and each of our subsidiaries are exempt from registration as an investment company under the Investment Company Act. Under Section 3(a)(1)(A) of the Investment Company Act, a company is deemed to be an investment company if it is, or holds itself out as being, engaged primarily, or proposes to engage primarily, in the business of investing, reinvesting or trading in securities. Under Section 3(a)(1)(C) of the Investment Company Act, a company is deemed to be an investment company if it is engaged, or proposes to engage, in the business of investing, reinvesting, owning, holding or trading in securities and owns or proposes to acquire investment securities having a value exceeding 40% of the value of its total assets (exclusive of U.S. government securities and cash items) on an unconsolidated basis. We believe that our company and most, if not all, of our wholly and majority-owned subsidiaries will not be considered investment companies under either Section 3(a)(1)(A) or Section 3(a)(1)(C) of the Investment Company Act.

Additionally, Rule 3a-1 under the Investment Company Act generally provides than an issuer will not be deemed to be an investment company under the Investment Company Act provided that (1) it does not hold itself out as being engaged primarily, or propose to engage primarily, in the business of investing, reinvesting or trading in securities, and (2) on an unconsolidated basis except as otherwise provided no more than 45% of the value of its total assets, consolidated with the assets of any wholly owned subsidiary (exclusive of government securities and cash items), consists of, and no more than 45% of its net income after taxes, consolidated with the net income of any wholly owned subsidiary (for the last four fiscal quarters combined), is derived from, securities other than government securities, securities issued by employees securities companies, securities issued by certain majority owned subsidiaries of such company and securities issued by certain companies that are controlled primarily by such company. We believe that we, our operating partnership and the subsidiaries of our operating partnership will satisfy this exclusion, and we will monitor our holdings to ensure continuing and ongoing compliance with Rule 3a-1.

A change in the value of any of our assets could cause us to fall within the definition of investment company and negatively affect our ability to maintain our exemption from regulation under the Investment Company Act. To avoid being required to register the company or any of its subsidiaries as an investment company under the Investment Company Act, we may be unable to sell assets we would otherwise want to sell and may need to sell assets we would otherwise wish to retain. In addition, we may have to acquire additional income- or loss-generating assets that we might not otherwise have acquired or may have to forgo opportunities to acquire interests in companies that we would otherwise want to acquire and would be important to our investment strategy.

If we were required to register our company as an investment company but failed to do so, we would be prohibited from engaging in our business, and criminal and civil actions could be brought against us. In addition, our contracts would be unenforceable unless a court required enforcement, and a court could appoint a receiver to take control of us and liquidate our business.

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High levels of debt or increases in interest rates could increase the amount of our loan payments, which could reduce the cash available for distribution to stockholders.

As mentioned above, we intend to incur debt. High debt levels would cause us to incur higher interest charges, would result in higher debt service payments, and could be accompanied by restrictive covenants. Interest we pay could reduce cash available for distribution to stockholders. Additionally, if we incur variable rate debt, increases in interest rates would increase our interest costs, which would reduce our cash flow and our ability to make distributions to our stockholders. If we need to repay existing debt during periods of rising interest rates, we could be required to liquidate one or more of our investments in properties at times which may not permit realization of the maximum return on such investments and could result in a loss.

Lenders may require us to enter into restrictive covenants relating to our operations, which could limit our ability to make distributions to our stockholders.

In providing financing to us, a lender may impose restrictions on us that affect our ability to incur additional debt, make certain investments, reduce liquidity below certain levels, make distributions to our stockholders and otherwise affect our distribution and operating policies. In general, we expect our loan agreements to restrict our ability to encumber or otherwise transfer our interest in the respective property without the prior consent of the lender. Such loan documents may contain other negative covenants that may limit our ability to discontinue insurance coverage, replace our advisor or impose other limitations. Any such restriction or limitation may have an adverse effect on our operations and our ability to make distributions to our stockholders. Further, such restrictions could make it difficult for us to satisfy the requirements necessary to maintain our qualification as a REIT for U.S. federal income tax purposes.

Some of our mortgage loans may have due on sale provisions, which may impact the manner in which we acquire, sell and/or finance our properties.

In purchasing properties subject to financing, we may obtain financing with due-on-sale and/or due-on-encumbrance clauses. Due-on-sale clauses in mortgages allow a mortgage lender to demand full repayment of the mortgage loan if the borrower sells the mortgaged property. Similarly, due-on-encumbrance clauses allow a mortgage lender to demand full repayment if the borrower uses the real estate securing the mortgage loan as security for another loan. These clauses may cause the maturity date of such mortgage loans to be accelerated and such financing to become due. In such event, we may be required to sell our properties on an all-cash basis, to acquire new financing in connection with the sale, or to provide seller financing. It is not our intent to provide seller financing, although it may be necessary or advisable for us to do so in order to facilitate the sale of a property. It is unknown whether the holders of mortgages encumbering our properties will require such acceleration or whether other mortgage financing will be available. Such factors will depend on the mortgage market and on financial and economic conditions existing at the time of such sale or refinancing.

Lenders may be able to recover against our other properties under our mortgage loans.

In financing our property acquisitions, we will seek to obtain secured nonrecourse loans. However, only recourse financing may be available, in which event, in addition to the property securing the loan, the lender may look to our other assets for satisfaction of the debt. Therefore, should we be unable to repay a recourse loan with the proceeds from the sale or other disposition of the property securing the loan, the lender could look to one or more of our other properties for repayment. Also, in order to facilitate the sale of a property, we may allow the buyer to purchase the property subject to an existing loan whereby we remain responsible for the debt.

If we are required to make payments under any bad boy carve-out guaranties that we may provide in connection with certain mortgages and related loans, our business and financial results could be materially adversely affected.

In obtaining certain nonrecourse loans, we may provide standard carve-out guaranties. These guaranties are only applicable if and when the borrower directly, or indirectly through agreement with an affiliate, joint venture partner or other third party, voluntarily files a bankruptcy or similar liquidation or reorganization action or takes other actions that are fraudulent or improper (commonly referred to as bad boy guaranties). Although we believe that bad boy carve-out guaranties are not guaranties of payment in the event of foreclosure or other actions of the foreclosing lender that are beyond the borrower s control, some lenders in the real estate industry have recently sought to make claims for payment under such guaranties. In the event such a claim were made against us under a bad boy carve-out guaranty, following foreclosure on mortgages or related loan, and such claim were successful, our business and financial results could be materially adversely affected.

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We may be subject to risks related to interest rate fluctuations, and the derivative financial instruments that we may use may be costly and ineffective and may reduce the overall returns for our stockholders.

We may be subject to risks related to interest rate fluctuations if any of our debt is subject to a floating interest rate. To the extent that we use derivative financial instruments in connection with our floating interest rate debt, we will be exposed to credit, basis and legal enforceability risks. Derivative financial instruments may include interest rate swap contracts, interest rate cap or floor contracts, futures or forward contracts, options or repurchase agreements. In this context, credit risk is the failure of the counterparty to perform under the terms of the derivative contract. If the fair value of a derivative contract is positive, the counterparty owes us, which creates credit risk for us. Basis risk occurs when the index upon which the contract is based is more or less variable than the index upon which the hedged asset or liability is based, thereby making the hedge less effective. Finally, legal enforceability risks encompass general contractual risks, including the risk that the counterparty will breach the terms of, or fail to perform its obligations under, the derivative contract. If we are unable to manage these risks effectively, our results of operations, financial condition and ability to make distributions to stockholders will be adversely affected.

Complying with REIT requirements may limit our ability to hedge risk effectively.

The REIT provisions of the Code may limit our ability to hedge the risks inherent to our operations. As mentioned above, from time to time, we may enter into hedging transactions with respect to one or more of our assets or liabilities. Any income or gain derived by us from transactions that hedge certain risks, such as the risk of changes in interest rates, will not be treated as gross income for purposes of either the 75% or the 95% Gross Income Test, which are separate tests based on the composition of our gross income that we must satisfy to qualify as a REIT, unless specific requirements are met. Such requirements include that the hedging transaction be properly identified within prescribed time periods and that the transaction either (i) hedges risks associated with indebtedness issued by us that is incurred to acquire or carry real estate assets or (ii) manages the risks of currency fluctuations with respect to income or gain that qualifies under the 75% or 95% Gross Income Test (or assets that generate such income). To the extent that we do not properly identify such transactions as hedges, hedge with other types of financial instruments, or hedge other types of indebtedness, the income from those transactions is not likely to be treated as qualifying income for purposes of the 75% and 95% Gross Income Tests. As a result of these rules, we may have to limit the use of hedging techniques that might otherwise be advantageous, which could result in greater risks associated with interest rate or other changes than we would otherwise incur.

Compliance with Laws

The costs of compliance with environmental laws and other governmental laws and regulations may adversely affect our income and the cash available for any distributions.

All real property and the operations conducted on real property are subject to federal, state and local laws and regulations relating to environmental protection and human health and safety. Examples of Federal laws include: National Environmental Policy Act, the Comprehensive Environmental Response, Compensation, and Liability Act, the Solid Waste Disposal Act as amended by the Resource Conservation and Recovery Act, the Federal Water Pollution Control Act, the Federal Clean Air Act, the Toxic Substances Control Act, the Emergency Planning and Community Right to Know Act and the Hazard Communication Act. These laws and regulations generally govern wastewater discharges, air emissions, the operation and removal of underground and above-ground storage tanks, the use, storage, treatment, transportation and disposal of solid and hazardous materials, and the remediation of contamination associated with disposals. Some of these laws and regulations may impose joint and several liability on residents, owners or operators for the costs of investigation or remediation of contaminated properties, regardless of fault or the legality of the original disposal. In addition, the presence of these substances, or the failure to properly remediate these substances, may adversely affect our ability to sell or rent the property or to use the property as collateral for future borrowing.

There may also be potential liability associated with lead-based paint arising from lawsuits alleging personal injury and related claims. The existence of lead paint is especially a concern in residential units. A structure built prior to 1978 may contain lead-based paint and may present a potential for exposure to lead; however, structures built after 1978 are not likely to contain lead-based paint.

Properties values may also be affected by their proximity to electric transmission lines. Electric transmission lines are one of many sources of electro-magnetic fields, or EMFs, to which people may be exposed. Research completed regarding potential health concerns associated with exposure to EMFs has produced inconclusive results. Notwithstanding the lack of conclusive scientific evidence, some states now regulate the strength of electric and magnetic fields emanating from electric transmission lines, and other states have required transmission facilities to measure for levels of EMFs. On occasion, lawsuits have been filed (primarily against electric utilities) that allege personal injuries from exposure to transmission lines and EMFs, as well as from fear of adverse health effects due to such exposure. This fear of adverse health effects from transmission lines has been considered both when property values have been determined to obtain financing and in condemnation proceedings. We may not, in certain circumstances, search for electric transmission lines near our properties, but are aware of the potential exposure to damage claims by persons exposed to EMFs.

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Recently, indoor air quality issues, including mold, have been highlighted in the media and the industry is seeing mold claims from lessees rising. Due to such recent increase in mold claims and given that the law relating to mold is unsettled and subject to change, we could incur losses from claims relating to the presence of, or exposure to, mold or other microbial organisms, particularly if we are unable to maintain adequate insurance to cover such losses. We may also incur unexpected expenses relating to the abatement of mold on properties that we may acquire.

Limited quantities of asbestos-containing materials are present in various building materials such as floor coverings, ceiling texture material, acoustical tiles and decorative treatment. Environmental laws govern the presence, maintenance and removal of asbestos. These laws could be used to impose liability for release of, and exposure to, hazardous substances, including asbestos-containing materials, into the air. Such laws require that owners or operators of buildings containing asbestos (i) properly manage and maintain the asbestos, (ii) notify and train those who may come into contact with asbestos and (iii) undertake special precautions, including removal or other abatement, if asbestos would be disturbed during renovation or demolition of a building. These laws may allow third parties to seek recovery from owners or operators of real properties for personal injury associated with exposure to asbestos fibers. As the owner of our properties, we may be liable for any such costs.

Compliance with new or more stringent laws or regulations or stricter interpretation of existing laws may require material expenditures by us. We cannot assure stockholders that future laws, ordinances or regulations will not impose any material environmental liability, or that the current environmental condition of our properties will not be affected by the operations of residents, existing conditions of the land, operations in the vicinity of the properties, or the activities of unrelated third parties. In addition, there are various local, state and federal fire, health, life-safety and similar regulations that we may be required to comply with. Failure to comply with applicable laws and regulations could result in fines and/or damages, suspension of personnel of our advisor and/or other sanctions.

Discovery of previously undetected environmentally hazardous conditions may adversely affect our operating results.

Under various federal, state and local environmental laws, ordinances and regulations, a current or previous owner or operator of real property may be liable for the cost of removal or remediation of hazardous or toxic substances on, under or in such property. The costs of removal or remediation could be substantial. These laws often impose liability whether or not the owner or operator knew of, or was responsible for, the presence of the hazardous or toxic substances.

Environmental laws also may impose restrictions on the manner in which property may be used or businesses may be operated, and these restrictions may require substantial expenditures. Environmental laws provide for sanctions in the event of noncompliance and may be enforced by governmental agencies or, in certain circumstances, by private parties. Certain environmental laws and common law principles govern the presence, maintenance, removal and disposal of certain building materials, including asbestos and lead-based paint (which are both discussed above).

The cost of defending against such claims of liability, of compliance with environmental regulatory requirements, of remediating any contaminated property, or of paying personal injury claims could materially adversely affect our business, assets or results of operations and, consequently, amounts available for distribution to stockholders.

We cannot assure stockholders that properties which we acquire will not have any material environmental conditions, liabilities or compliance concerns. Accordingly, we have no way of determining at this time the magnitude of any potential liability to which we may be subject arising out of environmental conditions or violations with respect to the properties we own.

Our costs associated with and the risk of failing to comply with the Americans with Disabilities Act may affect cash available for distributions.

Our properties are generally expected to be subject to the Americans with Disabilities Act of 1990, as amended, or the Disabilities Act. Under the Disabilities Act, all places of public accommodation are required to comply with federal requirements related to access and use by disabled persons. The Disabilities Act has separate compliance requirements for public accommodations and commercial facilities that generally require that buildings and services be made accessible and available to people with disabilities. The Disabilities Act s requirements could require removal of access barriers and could result in the imposition of injunctive relief, monetary penalties or, in some cases, an award of damages. We will attempt to acquire properties that comply with the Disabilities Act or place the burden on the seller or a third party to ensure compliance with such laws. However, we cannot assure stockholders that we will be able to acquire properties or allocate responsibilities in this manner. If we cannot, our funds used for compliance with these laws may affect cash available for distributions and the amount of distributions to stockholders.

The multifamily properties we acquire must comply with Title III of the Disabilities Act, to the extent that such properties are public accommodations and/or commercial facilities as defined by the Disabilities Act. Compliance with the Disabilities Act could require removal of structural barriers to handicapped access in certain public areas of our multifamily properties where such removal is readily achievable. The Disabilities Act does not, however, consider residential properties, such as multifamily properties to be public accommodations or commercial facilities, except to the extent portions of such facilities, such as the leasing office, are open to the public.

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We must comply with the Fair Housing Amendments Act of 1988, or the FHAA, and failure to comply may affect cash available for distributions.

We must comply with the FHAA, which requires that apartment communities first occupied after March 13, 1991 be accessible to handicapped residents and visitors. Compliance with the FHAA could require removal of structural barriers to handicapped access in a community, including the interiors of apartment units covered under the FHAA. Recently there has been heightened scrutiny of multifamily housing communities for compliance with the requirements of the FHAA and Disabilities Act and an increasing number of substantial enforcement actions and private lawsuits have been brought against apartment communities to ensure compliance with these requirements. Noncompliance with the FHAA could result in the imposition of fines, awards of damages to private litigants, payment of attorneys fees and other costs to plaintiffs, substantial litigation costs and substantial costs of remediation.

United States Federal Income Tax Risks

If we fail to qualify as a REIT, we will be subjected to tax on our income, and the amount of distributions we make to our stockholders will be less.

We intend to qualify as a REIT under the Code. A REIT generally is not taxed at the corporate level on income and gains that it distributes to its stockholders on a timely basis. Although we do not intend to request a ruling from the Internal Revenue Service, or the IRS, as to our REIT status, we have received the opinion of our tax counsel, Alston & Bird LLP, with respect to our qualification as a REIT. Investors should be aware, however, that opinions of counsel are not binding on the IRS or on any court. The opinion of Alston & Bird LLP represents only the view of our counsel based on our counsel s review and analysis of existing law and on certain representations as to factual matters and covenants made by us, including representations relating to the values of our assets and the sources of our income and representations related to our future conduct. Alston & Bird LLP has no obligation to advise us or the holders of our common stock of any subsequent change in the matters stated, represented or assumed in its opinion or of any subsequent change in applicable law. Qualification as a REIT involves the application of highly technical and complex rules for which there are only limited judicial or administrative interpretations. The determination of various factual matters and circumstances not entirely within our control may affect our ability to continue to qualify as a REIT. In addition, new legislation, regulations, administrative interpretations or court decisions could significantly change the tax laws with respect to qualification as a REIT or the U.S. federal income tax consequences of such qualification, including changes with retroactive effect.

If we elect to be taxed as a REIT and then were to fail to qualify as a REIT in any taxable year:

- we would not be allowed to deduct our distributions to our stockholders when computing our taxable income;
- we would be subject to U.S. federal income tax (including any applicable alternative minimum tax) on our taxable income at regular corporate rates;
- we could be disqualified from being taxed as a REIT for the four taxable years following the year during which qualification was lost, unless entitled to relief under certain statutory provisions;
- we would have less cash to make distributions to our stockholders; and
- we might be required to borrow additional funds or sell some of our assets in order to pay corporate tax obligations we may incur as a result of our disqualification.

Although we intend to operate in a manner intended to qualify as a REIT, it is possible that future economic, market, legal, tax or other considerations may cause our board of directors to determine to delay or revoke our REIT election. Even if we qualify as a REIT, we expect to incur some taxes, such as state and local taxes, taxes imposed on certain subsidiaries and potential U.S. federal excise taxes.

To qualify as a REIT we must meet annual distribution requirements, which may result in us distributing amounts that may otherwise be used for our operations.

To obtain the favorable tax treatment accorded to REITs, we generally will be required each year to distribute to our stockholders at least 90% of our REIT taxable income (excluding net capital gain), determined without regard to the deduction for distributions paid. We will be subject to U.S. federal income tax on our undistributed taxable income and net capital gain and to a 4% nondeductible excise tax on any amount by which distributions we pay with respect to any calendar year are less than the sum of (i) 85% of our ordinary income, (ii) 95% of our capital gain net income and (iii) 100% of our undistributed income from prior years. These requirements could cause us to distribute amounts that otherwise would be spent on investments in real estate assets, and it is possible that we might be required to borrow funds, possibly at unfavorable rates, or sell assets to fund these distributions. Although we intend to make distributions sufficient to meet the annual distribution requirements and to avoid U.S. federal income and excise taxes on our earnings, it is possible that we might not always be able to do so.

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Complying with REIT requirements may cause us to forgo otherwise attractive opportunities.

To qualify as a REIT, we must continually satisfy various tests regarding sources of income, nature and diversification of assets, amounts distributed to shareholders and the ownership of common shares. In order to satisfy these tests, we may be required to forgo investments that might otherwise be made. Accordingly, compliance with the REIT requirements may hinder our investment performance.

In particular, at least 75% of our total assets at the end of each calendar quarter must consist of real estate assets, government securities, and cash or cash items. For this purpose, real estate assets generally include interests in real property, such as land, buildings, leasehold interests in real property, stock of other entities that qualify as REITs, interests in mortgage loans secured by real property, investments in stock or debt instruments during the one-year period following the receipt of new capital and regular or residual interests in a real estate mortgage investment conduit, or REMIC. In addition, the amount of securities of a single issuer that we hold must generally not exceed either 5% of the value of such issuer s gross assets or 10% of the vote or value of such issuer s outstanding securities.

A REIT s net income from prohibited transactions is subject to a 100% penalty tax. In general, prohibited transactions are sales or other dispositions of property, other than foreclosure property, but including any mortgage loans, held in inventory or primarily for sale to customers in the ordinary course of business. The prohibited transaction tax may apply to any sale of assets to a securitization and to any sale of securitization securities, and therefore may limit our ability to sell assets to or equity in securitizations and other assets.

It may be possible to reduce the impact of the prohibited transaction tax and the holding of assets not qualifying as real estate assets for purposes of the REIT asset tests by conducting certain activities, holding non-qualifying REIT assets or engaging in securitization transactions through our TRSs, subject to certain limitations as described below. To the extent that we engage in such activities through TRSs, the income associated with such activities may be subject to full U.S. federal corporate income tax.

Stockholders may have current tax liability on distributions that they elect to reinvest in shares of our common stock.

If stockholders participate in our distribution reinvestment program, they will be deemed to have received a cash distribution equal to the fair market value of the stock received pursuant to the program. For U.S. federal income tax purposes, stockholders will be taxed on this amount in the same manner as if they have received cash. Further, to the extent that we have current or accumulated earnings and profits (as determined for U.S. federal income tax purposes), they will have ordinary taxable income except to the extent, if any, we have designated such amount as a capital gain dividend. To the extent that we make a distribution in excess of such earnings and profits, the distribution will be treated first as a tax-free return of capital, which will reduce the tax basis in their stock, and the amount of the distribution in excess of such basis will be taxable as a gain realized from the sale of their common stock. As a result, unless the stockholder is a tax-exempt entity, it may have to use funds from other sources to pay its tax liability on the value of the common stock received.

Certain of our business activities are potentially subject to the prohibited transaction tax, which could reduce the return for stockholders.

Our ability to dispose of property during the first few years following acquisition is restricted to a substantial extent as a result of our REIT status. Under applicable provisions of the Code regarding prohibited transactions by REITs, we will be subject to a 100% tax on any gain recognized on the sale or other disposition of any property (other than foreclosure property) that we own, directly or through any subsidiary entity, including our operating partnership, but excluding our taxable REIT subsidiaries, that is deemed to be inventory or property held primarily for sale to customers in the ordinary course of trade or business. Whether property is inventory or otherwise held primarily for sale to customers in the ordinary course of a trade or business depends on the particular facts and circumstances surrounding each property. No assurance can be given that any particular property we own, directly or through any subsidiary entity, including our operating partnership, but excluding our taxable REIT subsidiaries, will not be treated as inventory or property held primarily for sale to customers in the ordinary course of a trade or business.

The use of taxable REIT subsidiaries would increase our overall tax liability.

Some of our assets may need to be owned or sold, or some of our operations may need to be conducted, by taxable REIT subsidiaries. Any of our taxable REIT subsidiaries will be subject to U.S. federal and state income tax on their taxable income. The after-tax net income of our taxable REIT subsidiaries would be available for distribution to us. Further, we will incur a 100% excise tax on transactions with our taxable REIT subsidiaries that are not conducted on an arm s length basis. For example, to the extent that the rent paid by one of our taxable REIT subsidiaries exceeds an arm s length rental amount, such amount is potentially subject to the excise tax. We intend that all transactions between us and our taxable REIT subsidiaries will be conducted on an arm s length basis, and therefore, any amounts paid by our taxable REIT subsidiaries to us will not be subject to the excise tax; provided, however, no assurance can be given that no excise tax would arise from such transactions.

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Legislative or regulatory action could adversely affect the returns to our investors.

In recent years, numerous legislative, judicial and administrative changes have been made in the provisions of U.S. federal income tax laws applicable to investments similar to an investment in shares of our common stock. Additional changes to the tax laws are likely to continue to occur, and we cannot assure stockholders that any such changes will not adversely affect the taxation of a stockholder. Any such changes could have an adverse effect on an investment in our shares or on the market value or the resale potential of our assets. Stockholders are urged to consult with their own tax adviser with respect to the impact of recent legislation on their investment in our shares and the status of legislative, regulatory or administrative developments and proposals and their potential effect on an investment in our shares. Stockholders also should note that our counsel s tax opinion was based upon existing law and Treasury Regulations, applicable as of the date of its opinion, all of which will be subject to change, either prospectively or retroactively.

Although REITs continue to receive substantially better tax treatment than entities taxed as corporations, it is possible that future legislation would result in a REIT having fewer tax advantages, and it could become more advantageous for a company that invests in real estate to elect to be taxed for U.S. federal income tax purposes as a corporation. As a result, our charter provides our board of directors with the power, under certain circumstances, to revoke or otherwise terminate our REIT election and cause us to be taxed as a corporation, without the vote of our stockholders. Our board of directors has fiduciary duties to us and our stockholders and could only cause such changes in our tax treatment if it determines in good faith that such changes are in the best interest of our stockholders.

If the operating partnership fails to maintain its status as a partnership, its income may be subject to taxation.

We intend to maintain the status of the operating partnership as a partnership for U.S. federal income tax purposes. However, if the IRS were to successfully challenge the status of the operating partnership as a partnership for such purposes, it would be taxable as a corporation. In such event, this would reduce the amount of distributions that the operating partnership could make to us. This would also result in our losing REIT status, and becoming subject to a corporate level tax on our own income. This would substantially reduce our cash available to pay distributions and the yield on an investment in our shares. In addition, if any of the partnerships or limited liability companies through which the operating partnership owns its properties, in whole or in part, loses its characterization as a partnership for U.S. federal income tax purposes, it would be subject to taxation as a corporation, thereby reducing distributions to the operating partnership. Such a recharacterization of an underlying property owner could also threaten our ability to maintain REIT status.

Distributions to tax-exempt investors may be classified as unrelated business taxable income, or UBTI, and tax-exempt investors would be required to pay tax on such income and to file income tax returns.

Neither ordinary nor capital gain distributions with respect to our common stock nor gain from the sale of stock should generally constitute UBTI to a tax-exempt investor. However, there are certain exceptions to this rule, including:

- under certain circumstances, part of the income and gain recognized by certain qualified employee pension trusts with respect to our stock may be treated as UBTI if our stock is predominately held by qualified employee pension trusts, such that we are a pension-held REIT (which we do not expect to be the case);

- part of the income and gain recognized by a tax exempt investor with respect to our stock would constitute UBTI if such investor incurs debt in order to acquire the common stock; and

- part or all of the income or gain recognized with respect to our stock held by social clubs, voluntary employee benefit associations, supplemental unemployment benefit trusts and qualified group legal services plans which are exempt from U.S. federal income taxation under Sections 501(c)(7), (9), (17) or (20) of the Code may be treated as UBTI.

We encourage stockholders to consult their own tax advisor to determine the tax consequences applicable to them if they are a tax-exempt investor.

Distributions to foreign investors may be treated as an ordinary income distribution to the extent that it is made out of current or accumulated earnings and profits.

In general, foreign investors will be subject to regular U.S. federal income tax with respect to their investment in our stock if the income derived therefrom is effectively connected with the foreign investor s conduct of a trade or business in the United States. A distribution to a foreign investor that is not attributable to gain realized by us from the sale or exchange of a U.S. real property interest within the meaning of the Foreign Investment in Real Property Tax Act of 1980, as amended, or FIRPTA, and that we do not designate as a capital gain dividend, will be treated as an ordinary income distribution to the extent that it is made out of current or accumulated earnings and profits (as determined for U.S. federal income tax purposes). Generally, any ordinary income distribution will be subject to a U.S. federal income tax equal to 30% of the gross amount of the distribution, unless this tax is reduced by the provisions of an applicable treaty.

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Foreign investors may be subject to FIRPTA tax upon the sale of their shares of our stock.

A foreign investor disposing of a U.S. real property interest, including shares of stock of a U.S. corporation whose assets consist principally of U.S. real property interests, is generally subject to FIRPTA tax, on the gain recognized on the disposition. Such FIRPTA tax does not apply, however, to the disposition of stock in a REIT if the REIT is domestically controlled. A REIT is domestically controlled if less than 50% of the REIT s stock, by value, has been owned directly or indirectly by persons who are not qualifying U.S. persons during a continuous five-year period ending on the date of disposition or, if shorter, during the entire period of the REIT s existence. While we intend to qualify as domestically controlled, we cannot assure stockholders that we will do so. If we were to fail to so qualify, gain realized by foreign investors on a sale of shares of our stock would be subject to FIRPTA tax, unless the shares of our stock were traded on an established securities market and the foreign investor did not at any time during a specified testing period directly or indirectly own more than 5% of the value of our outstanding common stock.

Foreign investors may be subject to FIRPTA tax upon the payment of a capital gain dividend.

A foreign investor also may be subject to FIRPTA tax upon the payment of any capital gain dividend by us, which dividend is attributable to gain from sales or exchanges of U.S. real property interests. Additionally, capital gain dividends paid to foreign investors, if attributable to gain from sales or exchanges of U.S. real property interests, would not be exempt from FIRPTA and would be subject to FIRPTA tax.

We encourage stockholders to consult their own tax advisor to determine the tax consequences applicable to them if they are a foreign investor.

Employee Benefit Plan Risks

If stockholders fail to meet the fiduciary and other standards under ERISA or the Code as a result of ownership of our stock, they could be subject to liability and penalties.

Special considerations apply to the purchase of stock by employee benefit plans subject to the fiduciary rules of Title I of ERISA, including pension or profit sharing plans and entities that hold assets of such plans, or ERISA Plans, and plans and accounts that are not subject to ERISA, but are subject to the prohibited transaction rules of Section 4975 of the Code, including IRAs, Keogh Plans, and medical savings accounts (collectively, we refer to ERISA Plans and plans subject to Section 4975 of the Code as Benefit Plans). Stockholders who investing the assets of any Benefit Plan, should satisfy themselves that:

- their investment is consistent with their fiduciary obligations under ERISA and the Code;
- their investment is made in accordance with the documents and instruments governing the Benefit Plan, including the Benefit Plan s investment policy;
- their investment satisfies the prudence and diversification requirements of Sections 404(a)(1)(B) and 404(a)(1)(C) of ERISA, if applicable, and other applicable provisions of ERISA and the Code;
- their investment will not impair the liquidity of the Benefit Plan;
- their investment will not produce UBTI for the Benefit Plan;
- they will be able to value the assets of the plan annually in accordance with ERISA requirements and applicable provisions of the Benefit Plan; and

their investment will not constitute a prohibited transaction under Section 406 of ERISA or Section 4975 of the Code.

Fiduciaries may be held personally liable under ERISA for losses as a result of failure to satisfy the fiduciary standards of conduct and other applicable requirements of ERISA. In addition, if an investment in our stock constitutes a prohibited transaction under ERISA or the Code, the fiduciary of the plan who authorized or directed the investment may be subject to imposition of excise taxes with respect to the amount invested and an IRA investing in the stock may lose its tax exempt status.

Plans that are not subject to ERISA or the prohibited transactions of the Code, such as government plans or church plans, may be subject to similar requirements under state law. Such plans should satisfy themselves that the investment satisfies applicable law. We have not, and will not, evaluate whether an investment in our stock is suitable for any particular plan. Rather, we will accept entities as stockholders if an entity otherwise meets the suitability standards set forth in Investor Suitability Standards.

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ITEM 1B. ***Unresolved Staff Comments***

None.

ITEM 2. ***Properties***

The below table summarizes our investments in real estate, all of which are fee simple interests in multi-family properties as of December 31, 2011 (dollars in thousands, except average effective rent):

Property Name	State	Total Cost	Accumulated Depreciation	Carrying Amount	Encumbrances	Units	Average Occupancy	Average Effective Rent (a)(b)
Crestmont Apartments	GA	$ 16,333	$ (1,440)	$ 14,893	$ (6,750)	228	93.0%	$ 674
Cumberland Glen Apartments	GA	16,374	(1,454)	14,920	(6,900)	222	92.3	653
Copper Mill Apartments	TX	17,523	(1,548)	15,975	(7,350)	320	95.8	656
Heritage Trace Apartments	VA	13,544	(1,192)	12,352	(5,500)	200	92.7	741
Belle Creek Apartments	CO	9,668	(679)	8,989	(10,575)	162	95.4	829
Tresa at Arrowhead	AZ	35,646	(1,922)	33,724	(27,500)	360	91.4	766
Centrepoint Apartments	AZ	28,340	(1,069)	27,271	(17,600)	320	93.1	800
Total		$ 137,428	$ (9,304)	$ 128,124	$ (82,175)	1,812	93.4%	$ 721

(a) Based on operating performance from the date of acquisition through December 31, 2011.

(b) Average effective rent is rent per unit per month.

For additional information on our real estate portfolio, see Part I, Item I, Business Our Real Estate Portfolio.

We are substantially dependent on the net proceeds of our offering to meet our investment objective of acquiring a fully diversified portfolio of multifamily properties. If we are unable to raise a substantial amount of funds in our offering, we will make fewer investments resulting in less diversification in terms of the type, number and size of investments we make, and the value of an investment in us will fluctuate with the performance of the specific assets we acquire. Further, we will have certain fixed operating expenses, including certain expenses as a publicly offered REIT, regardless of whether we are able to raise substantial funds in our offering. Our inability to raise substantial funds would increase our fixed operating expenses as a percentage of gross income, reducing our net income and limiting our ability to make distributions.

In addition, after we have acquired a substantial portfolio of diversified investments, we intend to limit our aggregate leverage to 65% of the combined initial purchase price of all of our real estate properties. During the period when we are beginning our operations, we may employ greater leverage in order to more quickly build a diversified portfolio of assets.

ITEM 3. ***Legal Proceedings***

We are not subject to any material pending legal proceedings.

ITEM 4. ***Mine Safety Disclosures***

None.

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PART II

ITEM 5. ***Market for Registrant s Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities***

Market Information

Our shares of common stock are not currently listed on a national securities exchange or any over-the-counter market. Subject to then existing market conditions, we expect to consider alternatives for providing liquidity to our stockholders beginning five to seven years from the completion of our offering stage. We will consider our offering stage complete when we are no longer publicly offering equity securities in a public offering, whether through our ongoing public offering or follow-on offerings. For this purpose, we do not consider a public offering of equity securities to include offerings on behalf of selling stockholders or offerings related to a distribution reinvestment program, employee benefit plan or the redemption of interests in our operating partnership. While we expect to seek a liquidity transaction in this time frame, there can be no assurance that a suitable transaction will be available or that market conditions for a transaction will be favorable during that time frame. Our board of directors has the discretion to consider a liquidity transaction at any time if it determines such event to be in our best interests. A liquidity transaction could consist of a sale of our assets, a sale or merger of the company, a listing of our shares on a national securities exchange or a similar transaction. Some types of liquidity transactions require, after approval by our board of directors, approval of our stockholders. We do not have a stated term, as we believe setting a finite date for a possible, but uncertain future liquidity transaction may result in actions that are not necessarily in the best interest or within the expectations of our stockholders. A public market for our shares may allow us to increase our size, portfolio diversity, stockholder liquidity and access to capital. There is no assurance, however, that we will list our shares or that a public market will develop if we list our shares.

If we do not begin the process of listing our shares of common stock on a national securities exchange by the end of the mentioned period, or have not otherwise completed a liquidity transaction by such date, our charter requires that our board of directors determine, at least annually, whether a liquidity transaction is in our best interest. If a majority of our board of directors, including a majority of our independent directors, determines that a liquidity transaction is not then in the best interests of our stockholders, our charter requires that a majority of our board of directors, including a majority of our independent directors, revisit the issue of liquidation at least annually. Further postponement of listing or stockholder action regarding liquidation would only be permitted if a majority of our board of directors, including a majority of our independent directors, again determined that liquidation would not be in the best interest of our stockholders. If we sought and failed to obtain stockholder approval of our liquidation, our charter would not require us to list or liquidate, and we could continue to operate as before. If we sought and obtained stockholder approval of our liquidation, we would begin an orderly sale of our properties and other assets.

Even if we decide to liquidate, we are under no obligation to conclude our liquidation within a set time because the timing of the sale of our assets will depend on real estate and financial markets, economic conditions of the areas in which the properties are located, and U.S. federal income tax effects on stockholders that may prevail in the future. We cannot provide any assurance that we will be able to liquidate any or all of our assets. After commencing liquidation, we would continue in existence until all properties and other assets are liquidated.

In order for members of Financial Industry Regulatory Authority, Inc., or FINRA, and their associated persons to participate in our offering or any future offering of our common stock, we are required pursuant to FINRA Rule 5110 to disclose in each Annual Report distributed to our stockholders a per share estimated value of our shares of common stock, the method by which it was developed and the date of the data used to develop the estimated value. In addition, our advisor must prepare annual statements of estimated share values to assist fiduciaries of retirement plans subject to the annual reporting requirements of ERISA in the preparation of their reports relating to an investment in our common shares. For these purposes, the estimated value of the shares shall be deemed to be $10 per share as of December 31, 2011. The basis for this valuation is the fact that we are currently conducting a public offering of our common stock at the price of $10.00 per share.

Stockholder Information

As of March 9, 2011, there was one holder of record of our common shares.

Distributions

To qualify as a REIT, we are required to distribute 90% of our annual taxable income to our stockholders. In connection with a distribution to our stockholders, our board of directors approved a monthly distribution of a certain dollar amount per share of our common stock. If we do not have sufficient funds from operations to make distributions, we may need to borrow funds, request that our advisor, in its discretion, defer its receipt of fees and reimbursements of expenses or, to the extent necessary, utilize offering proceeds in order to make cash distributions. Our stockholders may choose whether to have distributions paid in cash or to have distributions otherwise payable to them in cash invested in additional shares of our common stock pursuant to the terms and conditions of our distribution reinvestment program.

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We did not declare any distribution for 2010. Distributions declared on our common stock for 2011 and the first quarter of 2012 are shown below, all of which were paid in cash.

		Common Shares		**Limited Partnership Units**	
		Dividends Declared per Share	Annualized Rate of Return(a)	Distributions Declared per Unit	Annualized Rate of Return(a)
2011	First Quarter	$	0%	$	0%
	Second Quarter		0%		0%
	Third Quarter	0.15	6.0%	0.15	6.0%
	Fourth Quarter	0.15	6.0%	0.15	6.0%
2012	First Quarter	$ 0.15	6.0%	$ 0.15	6.0%

(a) Based on a price per share and per unit of $10.00.

For the year ended December 31, 2011, including amounts paid to or allocable to our non-controlling interests, we paid cash distributions of $1.0 million, as compared to cash flows from operations of $2.2 million and FFO of $1.4 million. FFO is a non-GAAP financial measure. For a reconciliation of FFO to net income (loss), see Item 7. Management s Discussion and Analysis of Financial Condition and Results of Operations Non-GAAP Financial Measures.

We intend to pay comparable cash distributions in the future, but cannot guarantee that we will pay distributions at this rate or at all.

Use of Offering Proceeds

We sold 20,000 shares of our common stock to our advisor on April 30, 2009, for $10.00 per share. The issuance of these shares was exempt from the registration requirements of the Securities Act pursuant to Section 4(2) of the Securities Act and Regulation D promulgated thereunder. Our advisor is an indirect, wholly owned subsidiary of our sponsor. We invested the proceeds from this sale in partnership units of our operating partnership and, as a result, hold a 0.38% interest in our operating partnership. Our Advisor contributed $2,000 to our operating partnership in exchange for 200 limited partner units in our operating partnership. On January 20, 2011, our advisor transferred all of its interests in our operating partnership to RAIT NTR Holdings, LLC, an indirect, wholly owned subsidiary of our sponsor. The holders of limited partnership units have the right to redeem these units for cash equal to the value of an equivalent number of our common shares, or, at our option, we may purchase such units for cash or by issuing an equal number of our common shares, as permitted by the limited partnership agreement of our operating partnership.

On May 14, 2010, our Registration Statement on Form S-11 (File No. 333-160093) for an offering of a minimum of 250,000 shares and a maximum of 100,000,000 shares of common stock for sale to the public, which we refer to as the previous offering, at a price of $10.00 per share, which we refer to as the previous offering, was declared effective under the Securities Act by the SEC. Before our outstanding common stock was acquired on January 20, 2011 by a wholly owned subsidiary of our sponsor, during 2010, we suspended sales under the previous offering, refunded all subscriptions received and did not recommence selling our shares. On June 10, 2011, our Registration Statement on Form S-11 (File No. 333-173391) for an offering of a minimum of 250,000 shares and a maximum of 100,000,000 shares of common stock for sale to the public, which we refer to as our offering, at a price of $10.00 per share (subject to certain discounts) in the primary portion of the offering and $9.50 pursuant to our distribution reinvestment plan, which we refer to as the previous offering, was declared effective under the Securities Act by the SEC. Upon the SEC s declaration of effectiveness of our offering, our previous offering was automatically terminated before any shares were sold. As of March 9, we had issued 300,000 shares of our common stock pursuant to our offering, all of which were issued to a wholly owned subsidiary of our sponsor. We intend to use the proceeds from our offering to acquire a diverse portfolio of multifamily properties located in the United States.

As of December 31, 2011, we had invested in seven multifamily properties for a total purchase price of approximately $133 million. These acquisitions were funded from the issuance by our operating partnership of limited partnership units and the incurrence of approximately $82 million of mortgage indebtedness.

We will pay our advisor 1.0% of the gross offering proceeds for organizational and offering expenses (other than dealer manager fees and selling commissions). Our advisor and its affiliates are responsible for the payment of our organization and offering expenses, other than selling commissions and the dealer manager fee, to the extent they exceed 1.0% of our gross offering proceeds. As of December 31, 2011, we had not issued any shares pursuant to our offering and, therefore, had not made any payment to our advisor for organization and offering expenses. As of December 31, 2011, our advisor had incurred $3.5 million of organization and offering expenses on our behalf. We will also pay selling commissions and a dealer manager fee to our dealer manager as described in the prospectus. As of December 31, 2011, we had not paid any selling commissions or dealer manager fee to our dealer manager.

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Share Repurchase Program

We have adopted a share repurchase program that may enable stockholders to sell their shares to us in limited circumstances. During the year ended December 31, 2011, we did not repurchase any of our securities under our share repurchase program.

ITEM 6. ***Selected Financial Data***

The following selected financial data information should be read in conjunction with Item 7 Management s Discussion and Analysis of Financial Condition and Results of Operations, and our consolidated financial statements, including the notes thereto, included elsewhere herein.

Our results of operations for the year ended December 31, 2011 are not indicative of those expected in future periods. We have not yet invested all of the proceeds received to date from our public offering and expect to continue to raise additional capital, increase our borrowings and make future acquisitions, which would have a significant impact on our future results of operations. We were formed on March 26, 2009 and commenced our offering on June 10, 2011, but did not commence real estate operations until April 29, 2011 when we acquired six multifamily properties. As a result, we had no material results of operations for the period from March 26, 2009 (inception) to April 29, 2011. We subsequently acquired one additional multifamily property, the Centrepoint Apartments, on December 16, 2011. In general, we expect our results of operations to improve in future periods as a result of anticipated future acquisitions of real estate (dollars in thousands, except share and per share data).

	As of and for the Years Ended December 31		As of and for the Period from March 26, 2009 (inception) to December 31,
	2011	2010	2009
Operating Data:			
Total revenue	$ 8,668	$ 5	$ 2
Total expenses	(9,038)	(1)	(1)
Net income (loss)	(370)	4	1
Net income (loss) allocable to common shares	(112)	4	1
Earnings (loss) per share:			
Basic	$ (5.60)	$ 0.20	$ 0.06
Diluted	$ (5.60)	$ 0.20	$ 0.06
Balance Sheet Data:			
Investments in real estate	$ 128,124	$	$
Total assets	131,352	209	206
Total indebtedness	82,175		
Total liabilities	84,294	2	3
Total equity	47,058	207	203

	As of and for the year ended December 31		
	2011	2010	2009
Other Data:			
Common shares outstanding	20,000	20,000	20,000
Limited partnership units outstanding	5,274,900		
Cash distributions declared per common share/unit	$ 0.30	$	$

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ITEM 7. ***Management s Discussion and Analysis of Financial Condition and Results of Operations***

Overview

We were formed on March 26, 2009 as a Maryland corporation that intends to qualify as a real estate investment trust, or REIT, for the taxable year ended December 31, 2011. We are externally managed by our advisor, Independence Realty Advisors, LLC, an indirect, wholly owned subsidiary of our sponsor, RAIT Financial Trust (NYSE: RAS). We own substantially all of our assets and conduct our operations through Independence Realty Operating Partnership, LP, or our operating partnership, of which we are the sole general partner. As used herein, the terms we, our and us refer to our company and, as required by context, our operating partnership and their subsidiaries.

We intend to invest in a diversified portfolio of multifamily properties located throughout the United States. We target primarily core and stabilized multifamily properties that are well leased and produce predictable income. To a lesser extent we seek to acquire properties that require limited capital expenditures, have existing cash flow and offer opportunities for enhanced returns, with a primary focus on multifamily properties and a lesser focus on other asset classes.

Our investment objectives are to:

- pay attractive and consistent cash distributions;

- preserve invested capital; and

- provide a diversified direct investment in multifamily properties.

On May 14, 2010, our Registration Statement on Form S-11 (File No. 333-160093) for an offering of a minimum of 250,000 shares and a maximum of 100,000,000 shares of common stock for sale to the public, which we refer to as the previous offering, was declared effective under the Securities Act by the SEC. Before our outstanding common stock was acquired on January 20, 2011 by a wholly owned subsidiary of our sponsor, during 2010, we suspended sales under the previous offering, refunded all subscriptions received and did not recommence selling our shares. On June 10, 2011, our Registration Statement on Form S-11 (File No. 333-173391) for an offering of a minimum of 250,000 shares and a maximum of 100,000,000 shares of common stock for sale to the public, which we refer to as our offering, was declared effective under the Securities Act by the SEC. Upon the SEC s declaration of effectiveness of our offering, our previous offering was automatically terminated before any shares were sold. As of March 9, 2012, we had issued 300,000 shares pursuant to our offering. We intend to use the proceeds from our offering to acquire a diverse portfolio of multifamily properties located in the United States. Our offering will end no later than June 10, 2013 unless we elect to extend it to a date no later than June 10, 2014 in states that permit us to make this one-year extension.

Our Investment Portfolio

During 2011, we exited our development stage with the acquisition of six multifamily properties from our sponsor in April 2011. The aggregate purchase price for the properties was $103.8 million, exclusive of closing costs. In connection with the acquisition, we assumed $64.6 million in mortgage debt and our operating partnership issued $39.2 million in limited partnership units. In December 2011, we acquired a fee simple interest in our seventh multi-family property from our sponsor for an aggregate purchase price of $29.5 million, exclusive of closing costs, comprised of $17.6 million in cash and $11.9 million in limited partnership units of our operating partnership. As of December 31, 2011, the total cost of our real investment portfolio of seven multi-family properties with 1,812 units, was $137.4 million exclusive of closing costs. As of the same date, the average physical occupancy was 93.4% and the average monthly effective rent per unit was $721.

Non-GAAP Financial Measures

Funds from Operations and Modified Funds from Operations

We believe that funds from operations, or FFO, and modified funds from operations, or MFFO, each of which are non-GAAP measures, are additional appropriate measures of the operating performance of a REIT and us in particular. We compute FFO in accordance with the standards established by the National Association of Real Estate Investment Trusts, or NAREIT, as net income (loss) (computed in accordance with GAAP), excluding real estate-related depreciation and amortization expense, gains or losses on sales of real estate and after adjustments for unconsolidated partnerships and joint ventures.

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MFFO is a computation made by analysts and investors to measure a real estate company s cash flow generated by operations. We compute MFFO in accordance with the standards established by the Investment Program Association, or IPA, by adding to or subtracting from FFO: acquisition fees and expenses, straight-line rental adjustments, amortization of above or below market lease intangible assets or liabilities, amortization or accretion of premiums, discounts and deferred costs, non-recurring impairments, change in fair value of financial instruments, non-recurring gains or losses from the extinguishment or sale of assets or liabilities where trading of such holdings is not a fundamental attribute of the business plan, all of which after adjustments for consolidated and unconsolidated partnerships and joint ventures.

Our management utilizes FFO and MFFO as measures of our operating performance, and believes they are also useful to investors, because they facilitate an understanding of our operating performance after adjustment for certain non-cash items, such as real estate depreciation and various other items required by GAAP that may not necessarily be indicative of current operating performance and that may not accurately compare our operating performance between periods. Furthermore, although FFO, MFFO and other supplemental performance measures are defined in various ways throughout the REIT industry, we also believe that FFO and MFFO may provide us and our investors with an additional useful measure to compare our financial performance to certain other REITs.

MFFO has limitations as a performance measure in an offering such as ours where the price of a share of our common stock is a stated value and there is no net asset value determination during the offering stage and for a period thereafter. MFFO is useful in assisting management and investors in assessing the sustainability of operating performance in future operating periods, and in particular, after the offering and acquisition stages are complete and net asset value is disclosed. MFFO is not a useful measure in evaluating net asset value because impairments are taken into account in determining net asset value but not in determining MFFO.

Neither FFO nor MFFO is equivalent to net income or cash generated from operating activities determined in accordance with U.S. GAAP. Furthermore, FFO and MFFO do not represent amounts available for management s discretionary use because of needed capital replacement or expansion, debt service obligations or other commitments or uncertainties. Neither FFO nor MFFO should be considered as an alternative to net income as an indicator of our operating performance or as an alternative to cash flow from operating activities as a measure of our liquidity.

Set forth below is a reconciliation net income (loss) to FFO and MFFO for the years ended December 31, 2011, 2010 and 2009 (in thousands, except share information):

	For the Years Ended December 31 2011	2010	For the Period from March 26, 2009 (inception) to December 31, 2009
Funds From Operations:			
Net income (loss)	$ (370)	$ 4	$ 1
Adjustments:			
Real estate depreciation and amortization	1,771		
Funds from operations	$ 1,401	$ 4	$ 1
Weighted-average shares diluted (a)	4,146,260	20,000	20,000
Modified Funds From Operations:			
Funds From Operations	$ 1,401	$ 4	$ 1
Adjustments:			
Acquisition expenses	488		
Modified funds from operations	$ 1,889	$ 4	$ 1
Weighted-average shares diluted (a)	4,146,260	20,000	20,000

(a) Weighted-average shares diluted includes 4,146,260 limited partnership units that are convertible into common stock for the year ended December 31, 2011. No such units existed in 2010 or 2009. The limited partnership units are excluded in calculating weighted average shares in the consolidated financial statements because their effect was anti-dilutive.

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Results of Operations

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

We generated $8.7 million of revenue during the year ended December 31, 2011 as a result of the acquisition of six properties in April 2011 and one property in December 2011. Prior to the April acquisition, we did not own any revenue-producing assets and as such the financial information for the year ended December 31, 2011 is not comparable to the financial information for the year ended December 31, 2010. Our revenue for the year ended December 31, 2010 was comprised of interest income on short-term loans to our former sponsor in the aggregate principal amount of $200,000. These loans had a weighted average interest rate of 5.8%.

We incurred $7.3 million of expenses during the year ended December 31, 2011, comprised primarily of property operating expenses of $4.5 million, acquisition expenses of $0.5 million and depreciation and amortization of $1.8 million. As discussed above, these expenses relate to the acquisition and ownership of the seven properties we acquired in 2011. We incurred certain general and administrative expenses related to audit and other professional fees, trustee fees and other federal and state filing fees during the year ended December 31, 2011 of $0.6 million. We did not incur any expenses during the year ended December 31, 2010.

During the year ended December 31, 2011, we incurred $1.7 million of interest expense associated with the $82.2 million of mortgage indebtedness used to finance the seven properties we acquired in 2011.

Liquidity and Capital Resources

Liquidity is a measure of our ability to meet potential cash requirements, including ongoing commitments to repay borrowings, fund and maintain investments, pay distributions and other general business needs.

We believe our available cash balances, other financing arrangements and cash flows from operations will be sufficient to fund our liquidity requirements with respect to our existing portfolio for the next 12 months. We expect to raise capital in our offering, increase our borrowings and make future acquisitions, which would have a significant impact on our future results of operations. In general, we expect that our income and expenses related to our portfolio will increase in future periods as a result of anticipated future acquisitions of real estate. Should our liquidity needs exceed our available sources of liquidity, we believe that we could sell assets to raise additional cash. We may not be able to obtain additional financing when we desire to do so or on terms and conditions acceptable to us. If we fail to obtain additional financing, our ability to maintain or grow our business will be constrained.

Our primary cash requirements are to:

- make investments and fund the associated costs;
- repay our indebtedness;
- pay our operating and organization and offering expenses, including fees paid to our advisor and Jupiter Communites, LLC, our property manager;
- fund repurchases of shares pursuant to our share repurchase program; and
- distribute a minimum of 90% of our REIT taxable income and to make investments in a manner that enables us to maintain our qualification as a REIT.

We intend to meet these liquidity requirements primarily through:

the use of our cash and cash equivalent balances of $1.1 million as of December 31, 2011;

cash generated from operating activities;

proceeds from the sale of our common stock pursuant to our offering and our distribution reinvestment plan; and

proceeds from future borrowings.

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Cash Flows

As of December 31, 2011 and 2010, we maintained cash and cash equivalents of approximately $1.1 million and $0.2 million, respectively. Our cash and cash equivalents were generated from the following activities (dollars in thousands):

	For the Year Ended December 31 2011	2010	For the Period from March 26, 2009 (inception) to December 31, 2009
Cash flow from operating activities	$ 2,196	$ 3	$ 4
Cash flow from investing activities	(18,788)	0	0
Cash flow from financing activities	17,490	0	202
Net change in cash and cash equivalents	898	3	206
Cash and cash equivalents at beginning of period	209	206	0
Cash and cash equivalents at end of period	$ 1,107	$ 209	206

Our increased cash inflow from operating activities during the year ended December 31, 2011 is due to the acquisition of the seven multifamily properties in 2011.

Our cash outflows from investing activities is due to the cash used to acquire properties and capital expenditures during 2011.

The cash inflow from our financing activities during the year ended December 31, 2011 is substantially due to proceeds from mortgage indebtedness, offset by dividends/distributions we paid on our common shares and limited partnership units.

Contractual Commitments

The table below summarizes our contractual obligations as of December 31, 2011:

	Payment due by Period				
	Total	Less Than 1 Year	1-3 Years	3-5 Years	More Than 5 Years
	(dollars in thousands)				
Principal payments on outstanding debt obligations	$ 82,175	$	$ 515	$ 1,340	$ 80,320
Interest payments on outstanding debt obligations(a)	27,867	3,151	6,453	6,320	11,943
Total	$ 110,042	$ 3,151	$ 6,968	$ 7,660	$ 92,263

(a) All variable-rate indebtedness assumes a 30-day LIBOR rate of 0.435% (the 30-day LIBOR rate at December 31, 2011).

Review of Our Policies

Our board of directors, including our independent directors, has reviewed our policies described in this Annual Report and our registration statement and determined that they are in the best interest of our stockholders because (1) they increase the likelihood that we will be able to acquire a diversified portfolio of income-producing multifamily properties, thereby reducing risk in our portfolio; (2) there are sufficient property acquisition opportunities with the attributes that we seek; (3) our executive officers, our directors, the affiliates of our advisor and our property manager have expertise with the type of real estate investments we seek; and (4) borrowings should enable us to purchase assets and earn rental income more quickly, thereby increasing our likelihood of generating income for our stockholders and preserving stockholder capital.

Critical Accounting Estimates and Policies

We consider the accounting policies discussed below to be critical to an understanding of how we report our financial condition and results of operations because their application places the most significant demands on the judgment of our management.

Our financial statements are prepared on the accrual basis of accounting in accordance with GAAP. The preparation of financial statements in conformity with GAAP requires management to make use of estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenue and expenses during the reporting periods. Actual results could differ from those estimates.

Revenue Recognition

Minimum rents are recognized on an accrual basis, over the terms of the related leases on a straight-line basis. Any above-market lease values and the capitalized below-market lease values are amortized as an adjustment to rental income over the lease term. Recoveries from residential tenants for utility costs are recognized as revenue in the period that the applicable costs are incurred.

Investments in Real Estate

Allocation of Purchase Price of Acquired Assets

We account for acquisitions of properties in accordance with FASB ASC Topic 805, Business Combinations . The fair value of the real estate acquired is allocated to the acquired tangible assets, consisting of land, building and tenant improvements, and identified intangible assets and liabilities, consisting of the value of above-market and below-market leases for acquired in-place leases and the value of tenant relationships, based in each case on their fair values. Purchase accounting is applied to assets and liabilities associated with the real estate acquired. Transaction costs and fees incurred related to acquisitions are expensed as incurred. Transaction costs and fees incurred related to the acquisition of a joint venture interest, accounted for under the equity method of accounting, are capitalized as part of the cost of the investment.

Upon the acquisition of properties, we estimate the fair value of acquired tangible assets (consisting of land, building and improvements) and identified intangible assets and liabilities (consisting of above and below-market leases, in-place leases and tenant relationships), and assumed debt at the date of acquisition, based on the evaluation of information and estimates available at that date. Based on these estimates, we allocate the initial purchase price to the applicable assets and liabilities. As final information regarding fair value of the assets acquired and liabilities assumed is received and estimates are refined, appropriate adjustments will be made to the purchase price allocation, in no case later than twelve months of the acquisition date.

In determining the fair value of the identified intangible assets and liabilities of an acquired property, above-market and below-market in-place lease values are recorded based on the present value (using an interest rate which reflects the risks associated with the leases acquired) of the differences between (i) the contractual amounts to be paid pursuant to the in-place leases and (ii) management s estimate of fair market lease rates for the corresponding in-place leases, measured over a period equal to the remaining term of the lease. The capitalized above-market lease values and the capitalized below-market lease values are amortized as an adjustment to rental income over the lease term.

The aggregate value of in-place leases is determined by evaluating various factors, including an estimate of carrying costs during the expected lease-up periods, current market conditions and similar leases. In estimating carrying costs, management includes real estate taxes, insurance and other operating expenses, and estimates of lost rental revenue during the expected lease-up periods based on current market demand. Management also estimates costs to execute similar leases including leasing commissions, legal and other related costs. The value assigned to this intangible asset is amortized over the remaining lease terms.

Impairment of Long-Lived Assets

Management evaluates the recoverability of its investment in real estate assets, including related identifiable intangible assets, in accordance with FASB ASC Topic 360, Property, Plant and Equipment . This statement requires that long-lived assets be reviewed for impairment whenever events or changes in circumstances indicate that recoverability of the assets is not assured.

Management evaluates the long-lived assets on an ongoing basis and records an impairment charge when there is an indicator of impairment. The estimated cash flows used for the impairment analysis and the determination of estimated fair value are based on our plans for the respective assets and our views of market and economic conditions. The estimates consider matters such as current and historical rental rates, occupancies for the respective and/or comparable properties, and recent sales data for comparable properties. Changes in estimated future cash flows due to changes in our plans or views of market and economic conditions could result in recognition of impairment losses, which, under the applicable accounting guidance, could be substantial.

Recent Accounting Pronouncements

On January 1, 2011, we adopted ASU No. 2010-29, Disclosure of Supplementary Pro Forma Information for Business Combinations. This accounting standard requires that if a public entity presents comparative financial statements, the entity should disclose revenue and earnings of the combined entity as though the business combination(s) that occurred during the current year had occurred as of the beginning of the comparable prior annual reporting period only. This accounting standard expands the supplemental pro forma disclosures under FASB ASU Topic 805, Business Combinations to include a description of the nature and amount of material, nonrecurring pro forma adjustments directly attributable to the business combination included in the reported pro forma revenue and earnings. The adoption of this standard did not have a material effect on our consolidated financial statements.

In December 2011, the FASB issued an accounting standard classified under FASB ASC Topic 360, Property, Plant, and Equipment. This accounting standard amends existing guidance to resolve the diversity in practice about whether the guidance for real estate sales applies to a parent that ceases to have a controlling financial interest in a subsidiary that is in substance real estate as a result of default on the subsidiary s nonrecourse debt. This accounting standard is effective for fiscal years, and interim periods with those years, beginning on or after June 15, 2012. Management is currently evaluating the impact that these standards may have on our consolidated financial statements.

Subsequent Events

Sale of Preferred Stock

On January 4, 2012, we issued and sold 125 shares of our newly designated 12.5% Series A Cumulative Non-Voting Preferred Stock, $0.01 par value per share, which we refer to as the Series A Preferred Stock, for a purchase price of $1,000 per share, or $125,000 in the aggregate, to 125 accredited investors who are not affiliated with us. We intend to qualify and elect to be taxed as a REIT beginning with the taxable year ending December 31, 2011. One requirement we must meet to qualify as a REIT is that 100 or more persons must own our outstanding shares of capital stock during at least 335 days of a taxable year of 12 months, other than our first REIT taxable year. We expect that the sale of our Series A Preferred Stock will ensure that we can meet this requirement.

In connection with our sale of the Series A Preferred Stock, our operating partnership created a series of 125 preferred units of the operating partnership designated as 12.5% Series A Preferred Units, which we refer to as the Series A Preferred Units. The Series A Preferred Units rank senior to all other equity securities issued by our operating partnership and have preferential rights with respect to distributions, liquidation and redemption. Promptly after the closing of our sale of the Series A Preferred Stock to our sponsor, we contributed the proceeds from such sale to our operating partnership in exchange for 125 Series A Preferred Units.

Declaration of Distributions

On February 15, 2012, our board of directors authorized and declared distributions on our Series A Preferred Stock for the quarterly period ending on March 31, 2012. The distributions will be payable to the holders of the Series A Preferred Stock of record at a rate of $0.34153005 per day, which is an amount that is equivalent to a 12.5% annualized distribution rate based on a share price of $1,000.00. The distributions will be aggregated and paid in cash on July 29, 2012, pursuant to the requirements of our charter.

On February 15, 2012, our board of directors authorized and declared distributions on our common stock for the months of January, February and March 2012. The distributions will be payable to the holders of our common stock of record at a rate of $0.00163934 per day, which is an amount that is equivalent to a 6.0% annualized distribution rate based on a share price of $10.00. The distributions for each month will be aggregated and paid on or before the fifteenth day following the completion of each respective month. All distributions will be paid in cash or reinvested in stock for those participating in our distribution reinvestment plan.

Status of Our Public Offering and Sale of Common Stock to Our Sponsor

Pursuant to the terms of our offering, which we commenced our offering on June 10, 2011, we are required to terminate the offering and promptly return investors subscription payments, with interest, in the event that we do not sell a minimum of $2,500,000 in shares of our common stock. On February 29, 2012, we satisfied the minimum offering amount as a result of our sale of $3,000,000 in shares of our common stock for $10.00 per share in our offering to a wholly owned subsidiary of our sponsor in exchange for cash.

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ITEM 7A. ***Quantitative and Qualitative Disclosures About Market Risk***

Market risk is the adverse effect on the value of a financial instrument that results from a change in interest rates. We may be exposed to interest rate changes primarily as a result of long-term debt used to maintain liquidity, fund capital expenditures and expand our real estate investment portfolio and operations. Market fluctuations in real estate financing may affect the availability and cost of funds needed to expand our investment portfolio. In addition, restrictions upon the availability of real estate financing or high interest rates for real estate loans could adversely affect our ability to dispose of real estate in the future. We will seek to limit the impact of interest rate changes on earnings and cash flows and to lower our overall borrowing costs. We may use derivative financial instruments to hedge exposures to changes in interest rates on loans secured by our assets. The market risk associated with interest-rate contracts is managed by establishing and monitoring parameters that limit the types and degree of market risk that may be undertaken. With regard to variable rate financing, our advisor will assess our interest rate cash flow risk by continually identifying and monitoring changes in interest rate exposures that may adversely impact expected future cash flows and by evaluating hedging opportunities. Our advisor will maintain risk management control systems to monitor interest rate cash flow risk attributable to both our outstanding and forecasted debt obligations as well as our potential offsetting hedge positions. While this hedging strategy will be designed to minimize the impact on our net income and funds from operations from changes in interest rates, the overall returns on your investment may be reduced. We currently have limited exposure to financial market risks.

We will also be exposed to credit risk. Credit risk is the failure of the counterparty to perform under the terms of the derivative contract. If the fair value of a derivative contract is positive, the counterparty will owe us, which creates credit risk for us. If the fair value of a derivative contract is negative, we will owe the counterparty and, therefore, do not have credit risk. We will seek to minimize the credit risk in derivative instruments by entering into transactions with high-quality counterparties.

Interest Rate Risk and Sensitivity

Interest rates may be affected by economic, geo-political, monetary and fiscal policy, market supply and demand and other factors generally outside our control, and such factors may be highly volatile. A change in market interest rates applicable to the fixed portion of our indebtedness affects the fair value, but it has no effect on interest incurred or cash flows. A change in market interest rates applicable to the variable portion of our indebtedness affects the interest incurred and cash flows, but does not affect the fair value.

As of December 31, 2011, our only interest rate sensitive assets or liabilities related to our $82.2 million of indebtedness. We monitor interest rate risk routinely and seek to minimize the possibility that a change in interest rates would impact the interest incurred and our cash flows. To mitigate such risk, we will use interest rate derivative contracts. As of December 31, 2011, we do not have any interest rate derivatives in effect as all of our interest rate sensitive liabilities were fixed rate.

As of December 31, 2011, the fair value of our fixed-rate indebtedness was $85.8 million. The fair value estimate of our fixed rate debt was estimated using a discounted cash flow analysis utilizing rates we would expect to pay for debt of a similar type and remaining maturity if the loans were originated at December 31, 2011. A 100 basis point increase in market interest rates would decrease the fair value of our fixed-rate indebtedness by $3.7 million. A 100 basis point decrease in market interest rates would increase the fair value of our fixed-rate indebtedness by $3.9 million. As we expect to hold our fixed rate instruments to maturity and the amounts due under such instruments would be limited to the outstanding principal balance and any accrued and unpaid interest, we do not expect that fluctuations in interest rates, and the resulting change in fair value of our fixed rate instruments, would have a significant impact on our operations.

ITEM 8. ***Financial Statements and Supplementary Data***

INDEX TO FINANCIAL STATEMENTS

OF INDEPENDENCE REALTY TRUST, INC.

(A Maryland Corporation)

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholder

Independence Realty Trust, Inc.

We have audited the accompanying consolidated balance sheets of Independence Realty Trust, Inc. (formerly Empire American Realty Trust, Inc.) (a Maryland corporation) and subsidiaries (the Company) as of December 31, 2011 and 2010 and the related consolidated statements of operations, changes in equity, and cash flows for the years ended December 31, 2011 and 2010 and for the period from March 26, 2009 (date of inception) through December 31, 2009. Our audits of the basic consolidated financial statements included the financial statement schedule listed in the index appearing under Item 15(2). 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 based on our audits.

We conducted our audits in the 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. We were not engaged to perform an audit of the Company s internal control over financial reporting. Our audit included consideration of internal control over financial reporting as a basis for designing audit procedures that are appropriate in the circumstances, but not for the purpose of expressing an opinion on the effectiveness of the Company s internal control over financial reporting. Accordingly, we express no such opinion. An audit also includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the consolidated financial statements referred to above present fairly, in all material respects, the consolidated financial position of the Company as of December 31, 2011 and 2010 and the consolidated results of their operations and their cash flows for the year ended December 31, 2011 and 2010 and for the period from March 26, 2009 (date of inception) through December 31, 2009, in conformity with accounting principles generally accepted in The United States of America. Also in our opinion, the related financial statement schedule, when considered in relation to the basic consolidated financial statements taken as a whole, presented fairly, in all material respects, the information set forth therein.

/s/ Grant Thornton LLP

Philadelphia, Pennsylvania

March 9, 2012

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Independence Realty Trust, Inc. and Subsidiaries

Consolidated Balance Sheets

(Dollars in thousands, except share and per share data)

	As of December 31, 2011	As of December 31, 2010
ASSETS:		
Investments in real estate, net of accumulated depreciation of $9,304 and $0, respectively	$ 128,124	$ 0
Cash and cash equivalents	1,107	209
Restricted cash	1,072	0
Accounts receivable and other assets	543	0
Deferred costs, net of accumulated amortization of $15 and $0, respectively	506	0
Total assets	$ 131,352	$ 209
LIABILITIES AND EQUITY:		
Mortgage indebtedness	$ 82,175	$ 0
Accounts payable and accrued expenses	1,529	2
Other liabilities	590	0
Total liabilities	84,294	2
Equity:		
Stockholder s equity:		
Preferred stock, $0.01 par value; 50,000,000 shares authorized, no shares issued and outstanding	0	0
Common stock, $0.01 par value; 300,000,000 shares authorized, 20,000 shares issued and outstanding	0	0
Additional paid-in capital	200	200
Retained earnings (accumulated deficit)	(113)	5
Total stockholder s equity	87	205
Non-controlling interest	46,971	2
Total equity	47,058	207
Total liabilities and equity	$ 131,352	$ 209

The accompanying notes are an integral part of these consolidated financial statements.

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Independence Realty Trust, Inc. and Subsidiaries

Consolidated Statements of Operations

(Dollars in thousands, except share and per share data)

	For the Years Ended December 31 2011	2010	Period from March 26, 2009 (Date of inception) Through December 31 2009	
REVENUE:				
Rental income	$ 7,716	$ 0	$ 0	
Tenant reimbursement and other property income	441	0	0	
Other income	511	5	2	
Total revenue	8,668	5	2	
EXPENSES:				
Property operating expenses	4,477	0	0	
General and administrative expenses	575	0	0	
Acquisition expenses	488	0	0	
Depreciation and amortization	1,771	0	0	
Total expenses	7,311	0	0	
Operating Income	1,357	5	2	
Interest expense	(1,727)	0	0	
Net income (loss) before income taxes:	(370)	5	2	
Income tax provision	0	(1)	(1)	
Net income (loss)	(370)	4	1	
Loss allocated to non-controlling interest	258	0	0	
Net income (loss) allocable to common shares	$ (112)	$ 4	$ 1	
Earnings (loss) per share:				
Basic	$ (5.60)	$ 0.20	$ 0.06	
Diluted	$ (5.60)	$ 0.20	$ 0.06	
Weighted-average shares:				
Basic	–			
Total income tax expense	(13.9)		(11.9)	(25.8)
INCOME FROM CONTINUING OPERATIONS	22.2		(53.0)	41.2
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	(3.9)			(3.9)
NET INCOME	$ 18.3		$ (53.0)	$ 37.3

Earnings per share from continuing operations, basic and diluted	$ 1.18	$ 2.20
Cumulative change in accounting principle	(0.20)	(0.20)
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 0.98	$ 2.00
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC AND DILUTED	18,750	18,750

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NOTES TO THE UNAUDITED PRO FORMA STATEMENTS OF OPERATIONS

1. BASIS OF PRESENTATION

On September 23, 2004, we completed our acquisition of interests in seventeen oil and natural gas fields located in the Permian Basin of West Texas and Southeast New Mexico (the Permian Basin Acquisition Properties) from CQ Acquisition Partners I, L.P., SPA-CQAP II, Enerquest Oil & Gas, Ltd. and Baytech, L.L.P. The effective date of the purchase was July 1, 2004. The cash purchase price was $345 million subject to closing adjustments.

The following unaudited pro forma financial information shows the pro forma effect of the acquisition of the Permian Basin Acquisition Properties. It does not reflect the pro forma effect of any of our other recent acquisitions discussed in this prospectus. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include results from our Wyoming and Utah acquisition that closed on September 30, 2004. A pro forma balance sheet has not been presented since the acquisition has been reflected in our September 30, 2004 balance sheet of Whiting Petroleum Corporation, located elsewhere in this prospectus. The unaudited pro forma statement of operations for the nine months ended September 30, 2004 and for the year ended December 31, 2003 was prepared as if the acquisition had occurred at January 1, 2003.

The accompanying statements of revenues and direct operating expenses for the Permian Basin Acquisition Properties were derived from the historical accounting records of the sellers and prior operators. Although the statements do not include depreciation, depletion and amortization, general administrative expenses, income taxes or interest expense, as described in Notes 2 and 3, these costs have been included on a pro forma basis. The pro forma financial information also includes the effects of our bank credit agreement which was amended concurrent with the property acquisition. The terms of the amendment increased the credit facility to $750 million with a $480 million borrowing base. After the closing of this acquisition, the Company had $400 million of outstanding borrowings under the facility.

We believe that assumptions used provide a reasonable basis for presenting the significant effects directly attributable to such transactions.

The following unaudited pro forma financial statements do not purport to represent what our results of operations would have been if this acquisition had occurred on January 1, 2003. These unaudited pro forma financial statements should be read in conjunction with our historical financial statements and related notes for the periods presented.

Earnings Per Share Basic net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding during each period. Diluted net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding and other dilutive securities. The only securities considered dilutive are our unvested restricted stock awards. The dilutive effect of these securities were immaterial to the calculation.

2. PRO FORMA ADJUSTMENTS FOR NINE MONTHS ENDED SEPTEMBER 30, 2004

The accompanying unaudited condensed pro forma statement of operations for the nine months ended September 30, 2004 assumes the acquisition of the Permian Basin Acquisition Properties occurred as of January 1, 2003. The following adjustments have been made to the accompanying condensed pro forma statement of operations for the nine months ended September 30, 2004:

Revenues, Lease Operating and Production Taxes To adjust for the period from July 1, 2004 to the closing date of September 23, 2004.

Depletion, Depreciation and Amortization To record pro forma depletion expense giving effect to the acquisition of the Permian Basin Acquisition Properties. The expense was calculated using estimated proved reserves by field and the preliminary $345.0 million purchase price allocation. None of the purchase price was allocated to unproved properties.

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General and Administrative To record expenses associated with anticipated increases in personnel and office expansion. This adjustment also includes the estimated costs related to our production participation plan for the periods indicated. Under our production participation plan for the 2004 plan year, the estimated discounted value of the plan must be expensed immediately for employees over 65 years old and amortized over five years for the majority of other employees.

Interest Expense To record interest expense for additional debt and debt issuance costs incurred in connection with the Permian Basin Acquisition Properties. We used historical rates paid during the nine months ended September 30, 2004 which approximated 3.2%. Each 1/8% change in the interest rate would affect net income before income taxes by $295,000 for the nine month period.

Income Taxes To record income related to the pretax income from the Permian Basin Acquisition Properties for the period from January 1, 2004 to the closing date of September 23, 2004, based on our effective tax rate of 38.6%.

3. PRO FORMA ADJUSTMENTS FOR YEAR ENDED DECEMBER 31, 2003

The accompanying unaudited pro forma statement of operations for the year ended December 31, 2003 assumes the acquisition of the Permian Basin Acquisition Properties occurred as of January 1, 2003. The following adjustments have been made to the accompanying pro forma statement of operations for the year ended December 31, 2003:

Depletion, Depreciation and Amortization To record pro forma depletion expense giving effect to the acquisition of the Permian Basin Acquisition Properties. The expense was calculated using estimated proved reserves by field and the preliminary $345.0 million purchase price allocation.

General and Administrative To record expenses associated with anticipated increases in personnel and office expansion. This adjustment also includes the estimated costs related to our production participation plan for the periods indicated. Under our production participation plan, for the 2004 plan year, the estimated discounted value to the plan must be expensed immediately for employees over 65 years old and amortized over five years for the majority of other employees.

Interest Expense To record interest expense for additional debt and debt issuance costs incurred in connection with the Permian Basin Acquisition Properties. We used historical rates paid during the year ended December 31, 2003 which approximated 3.0%. Each 1/8% change in the interest rate would affect net income before income taxes by $394,000 for the year.

Income Taxes To record income related to the pretax income from the Permian Basin Acquisition Properties for the year ended December 31, 2003, based on our effective tax rate of 38.6%.

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SELECTED HISTORICAL FINANCIAL INFORMATION

The following selected historical financial information for each of the four years ended December 31, 2003, has been derived from our audited consolidated financial statements and related notes. The following selected historical financial information for the nine months ended September 30, 2004 and 2003 and the year ended December 31, 1999 and the balance sheet information as of December 31, 2000 and 1999 has been derived from our unaudited consolidated financial statements. This information is only a summary and you should read it in conjunction with material contained in the section entitled Management s Discussion and Analysis of Financial Condition and Results of Operations, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our financial statements and related notes included elsewhere in this prospectus. The unaudited interim period financial information, in our opinion, includes all adjustments, which are normal and recurring in nature, necessary for a fair presentation of the periods shown. Results for the nine months ended September 30, 2004 are not necessarily indicative of the results to be expected for the full fiscal year. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include the results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our balance sheet information as of September 30, 2004 does include the effect of such acquisition.

	Nine Months Ended September 30,		Year Ended December 31,				
	2004	2003	2003	2002	2001	2000	1999
	(dollars in millions, except per share data)						
Consolidated Income Statement Information:							
Revenues:							
Oil and gas sales	$ 166.4	$ 133.6	$ 175.8	$ 122.7	$ 125.2	$ 107.0	$ 60.9
Gain (loss) on oil and gas hedging activities	(3.6)	(9.0)	(8.7)	(3.2)	2.3	(3.8)	
Gain on sale of oil and gas properties	1.0			1.0	11.7	7.7	10.1
Gain on sale of marketable securities	4.7						
Interest income and other	0.2	0.2	0.3		0.2	0.1	0.1
Total revenues	$ 168.7	$ 124.8	$ 167.4	$ 120.5	$ 139.4	$ 111.0	$ 71.1
Costs and expenses:							
Lease operating	$ 34.6	$ 32.1	$ 43.2	$ 32.9	$ 29.8	$ 23.8	$ 20.7
Production taxes	10.2	8.1	10.7	7.4	6.5	5.4	3.0
Depreciation, depletion and amortization[1]	34.5	30.7	41.3	43.6	26.9	21.5	19.8
Exploration and impairment	4.7	1.0	3.2	1.8	0.8	1.1	5.2
Phantom equity plan[2]			10.9				
General and administrative	14.2	9.5	12.8	12.0	10.9	6.3	4.3
Interest expense	9.6	7.1	9.2	10.9	10.2	7.5	5.4
Total costs and expenses	$ 107.8	$ 88.5	$ 131.3	$ 108.6	$ 85.1	$ 65.6	$ 58.4
Income before income taxes and cumulative change in accounting principle	$ 60.9	$ 36.3	$ 36.1	$ 11.9	$ 54.3	$ 45.4	$ 12.7
Income tax expense[3]	(23.5)	(13.8)	(13.9)	(4.2)	(13.1)	(11.7)	(1.8)
Income from continuing operations	37.4	22.5	22.2	7.7	41.2	33.7	10.9

Cumulative change in accounting principle[4]		(3.9)	(3.9)				
Net income	$ 37.4	$ 18.6	$ 18.3	$ 7.7	$ 41.2	$ 33.7	$ 10.9
Net income per common share from continuing operations, basic and diluted	$ 1.93	$ 1.20	$ 1.18	$ 0.41	$ 2.20	$ 1.80	$ 0.58
Net income per common share, basic and diluted	$ 1.93	$ 0.99	$ 0.98	$ 0.41	$ 2.20	$ 1.80	$ 0.58
Other Financial Information:							
Net cash provided by operating activities	$ 96.9	$ 75.0	$ 96.4	$ 62.6	$ 62.3	$ 42.3	$ 38.7
Capital expenditures[5]	$ 498.1	$ 33.1	$ 52.0	$ 165.4	$ 99.6	$ 139.1	$ 34.9
EBITDA[6]	$ 105.0	$ 70.2	$ 82.6	$ 66.4	$ 91.4	$ 74.4	$ 37.9

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	As of September 30,		As of December 31,				
	2004	2003	2003	2002	2001	2000	1999
	(dollars in millions)						
Balance Sheet Information:							
Total assets	$ 1,054.6	$ 502.5	$ 536.3	$ 448.5	$ 319.8	$ 256.4	$ 148.5
Long-term debt[7]	$ 538.8	$ 185.0	$ 188.0	$ 265.5	$ 163.6	$ 139.7	$ 72.5
Stockholder s equity	$ 334.9	$ 224.9	$ 259.6	$ 122.8	$ 111.5	$ 70.0	$ 36.2

(1) We reduced the amount of our asset retirement obligations estimate from approximately $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 asset retirement obligations 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 valued at approximately $6.5 million after withholding of shares for payroll and income taxes. As a result, in the fourth quarter of 2003, we recorded a one-time non-cash charge of $6.5 million and a one-time cash charge of $4.4 million, of which Alliant Energy Corporation funded the substantial majority. The phantom equity plan is now terminated.

(3) We generated Section 29 tax credits of $3.0 million in 1999, $5.2 million in 2000, $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. The adoption of SFAS 143 included a one-time cumulative effect adjustment to net income.

(5) In 2003, we acquired the limited partnership interests in three partnerships in which our wholly owned subsidiary is the general partner. Though disclosed as acquisitions of limited partnership interests in our consolidated statements of cash flows, these amounts are recorded as oil and natural gas properties on our consolidated balance sheets and are included in capital expenditures in this selected historical financial information.

(6) We define EBITDA as earnings before interest, taxes, depreciation, depletion and amortization. EBITDA is not a measure of performance calculated in accordance with generally accepted accounting principles in the United States, or GAAP. Although not prescribed under GAAP, we believe the presentation of EBITDA is relevant and useful because it helps our investors to understand our operating performance and makes it easier to compare our results with other companies that have different financing and capital structures or tax rates. EBITDA should not be considered in isolation of, or as a substitute for, net income as an indicator of operating performance or cash flows from operating activities as a measure of liquidity. EBITDA, as we calculate it, may not be comparable to EBITDA measures reported by other companies. In addition, EBITDA does not represent funds available for discretionary use.

The following table presents a reconciliation of our consolidated net income to our consolidated EBITDA:

	Nine Months	Year Ended December 31,

	Ended September 30,						
	2004	**2003**	**2003**	**2002**	**2001**	**2000**	**1999**
Net income	$ 37.4	$ 18.6	$ 18.3	$ 7.7	$ 41.2	$ 33.7	$ 10.9
Income tax expense	23.5	13.8	13.9	4.2	13.1	11.7	1.8
Interest expense	9.6	7.1	9.2	10.9	10.2	7.5	5.4
Depreciation, depletion and amortization	34.5	30.7	41.2	43.6	26.9	21.5	19.8
EBITDA	$ 105.0	$ 70.2	$ 82.6	$ 66.4	$ 91.4	$ 74.4	$ 37.9

(7) Long-term debt as of September 30, 2004 does not include $50.0 million of long-term debt classified as current.

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MANAGEMENT S DISCUSSION AND

ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

The following discussion and analysis should be read in conjunction with our selected historical financial data and our accompanying financial statements and the notes to those financial statements included elsewhere in this prospectus. The following discussion includes forward-looking statements that reflect our plans, estimates and beliefs. Our actual results could differ materially from those discussed in these forward-looking statements. Factors that could cause or contribute to such differences include, but are not limited to, those discussed below and elsewhere in this prospectus, particularly in Risk Factors.

Overview

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Rocky Mountains, Permian Basin, Gulf Coast, Michigan, Mid-Continent and California regions of the United States. Over the last four 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 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 management is 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.

We completed five separate acquisitions of producing properties during the first nine months of 2004. The combined purchase price for these five acquisitions was $516.1 million for total estimated proved reserves as of the effective dates of the acquisitions of approximately 421.9 Bcfe. For more information on these acquisitions, see Business and Properties Recent Acquisitions. 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: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include the results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our balance sheet information as of September 30, 2004 does include the effect of such acquisition. See Unaudited Pro Forma Financial Statements for more information about how our historical results of operations would have been affected had our acquisition of the Permian Basin properties been completed on January 1, 2003.

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments and competition from other sources of energy. Oil and natural

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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.

Results of Operations

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

	Nine Months Ended September 30,		Years Ended December 31,		
	2004	2003	2003	2002	2001
Net production:					
Natural gas (Bcf)	17.1	16.1	21.6	21.4	19.8
Oil (MMbbls)	2.2	1.9	2.6	2.3	2.1
Net sales (in millions):					
Natural gas[(1)]	$ 90.6	$ 80.1	$ 104.4	$ 68.6	$ 75.4
Oil[(1)]	$ 75.8	$ 53.5	$ 71.3	$ 54.1	$ 49.8
Average sales price:					
Natural gas (per Mcf)[(1)]	$ 5.30	$ 4.98	$ 4.78	$ 3.21	$ 3.82
Oil (per Bbl)[(1)]	$ 35.13	$ 27.71	$ 27.50	$ 23.35	$ 23.85
Costs and expenses (per Mcfe):					
Lease operating expenses	$ 1.15	$ 1.16	$ 1.16	$ 0.93	$ 0.92
Production taxes	$ 0.34	$ 0.29	$ 0.29	$ 0.21	$ 0.20
Depreciation, depletion and amortization expense	$ 1.15	$ 1.11	$ 1.11	$ 1.24	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.47	$ 0.34	$ 0.34	$ 0.34	$ 0.34

(1) Before consideration of hedging transactions.

Nine Months Ended September 30, 2004 Compared to Nine Months Ended September 30, 2003

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased approximately $32.8 million to $166.4 million for the first nine months of 2004. Sales are a function of sales volumes and average sales prices. Our sales volumes increased 8.6% between periods on a Mcfe 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 decline. Our average price for natural gas sales increased 6.4% and our average price for crude oil increased 26.8% between periods.

Loss on Oil and Natural Gas Hedging Activities. We hedged 22% of our natural gas volumes during the first nine months of 2004 incurring no hedging loss or gain, and 42% of our natural gas volumes during the same period of 2003 incurring a hedging loss of $8.0 million. We hedged 42% of our oil volumes during the first nine months of 2004 incurring a hedging loss of $3.6 million, and 11% of our oil volumes during the same period of 2003 incurring a loss of $1.0 million. See Qualitative and Quantitative Disclosures About Market Risk for a list of our outstanding oil and natural gas hedges as of October 14, 2004.

Gain on Sale of Marketable Securities. During the initial nine months of 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 September 30, 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 held by production 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.

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Lease Operating Expenses. Our lease operating expenses per Mcfe decreased from $1.16 during the first nine months of 2003 to $1.15 during the same period in 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.

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. Due to our broad asset base, we expect our production tax rate to vary between 6.0% to 6.5% of oil and natural gas sales revenue. Our production taxes for the initial nine months of 2004 and 2003 were 6.1% of oil and natural gas sales.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (DD&A) increased $3.8 million to $34.5 million for the first nine months of 2004. The increase resulted from increased production and an increase in the DD&A rate. On a Mcfe basis, the rate increased from $1.11 during the first nine months of 2003 to $1.15 during the same period in 2004. We expect our DD&A rate to increase in the fourth quarter due to the effects of the recent acquisitions. 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 depreciation, depletion and amortization expense were as follows (in thousands):

	Nine Months Ended September 30,	
	2004	**2003**
Depletion	$ 32,736	$ 29,011
Depreciation	550	560
Accretion of asset retirement obligations	1,214	1,104
Total	$ 34,500	$ 30,675

Exploration and Impairment Costs. Our exploration and impairment costs increased $3.7 million to $4.7 million for the first nine months of 2004. The higher exploratory costs were related to our increased purchases of seismic 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.

	Nine Months Ended September 30,	
	2004	**2003**
Exploration	$ 2,534	$ 1,015
Impairment	2,152	
Total	$ 4,686	$ 1,015

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

	Nine Months Ended September 30,	
	2004	2003
General and administrative expenses	$ 18,016	$ 13,806
Reimbursements	(3,825)	(4,284)
General and administrative expense, net	$ 14,191	$ 9,522

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General and administrative expense before reimbursements increased $4.2 million to $18.0 million during the first nine months of 2004. On a Mcfe basis, the increase between nine month periods was from $0.34 to $0.47. The largest component of the increase related to costs associated with our production payment plan. During periods of increased acquisition activity, our general and administrative expense will be higher because we must immediately recognize the discounted value of estimated plan payments to employees 65 and older. The discounted value of estimated payments to employees under 65 is generally amortized over a five year vesting period. Costs related to the production payment plan increased $1.8 million between nine month periods. The remaining increase was primarily caused by the extra costs of functioning as a public company, increases in the employee base due to our continued growth and general cost inflation. The decrease in reimbursements was caused by our purchase of the limited partnership interests in three of the six remaining managed partnerships during the second quarter of 2003. We expect our general and administrative expense to decrease to under $0.38 per Mcfe sold in the fourth quarter due to cost synergies from recent acquisitions.

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

	Nine Months Ended September 30,	
	2004	**2003**
7 1/4% Senior Subordinated Notes due 2012	$ 3,875	$
Credit Facility	2,778	5,043
Alliant	113	1,207
Amortization of debt issue costs and debt discount	1,025	860
Accretion of tax sharing liability	1,800	
Total interest expense	$ 9,591	$ 7,110

The decrease in bank interest was primarily due to our $40.0 million pay down of our credit facility on February 17, 2004 and our repayment of the remaining principal balance outstanding under the credit facility on May 11, 2004 with the proceeds from the issuance of our 7 1/4% Senior Subordinated Notes due 2012. We expect our overall interest expense to increase during the remainder of 2004 due to the cash acquisitions closed during the third quarter of 2004, which increased the outstanding balance under our credit facility to $435 million as of September 30, 2004. In addition, in August, we entered into an interest rate swap causing the interest rate on $75 million of the 7 1/4% Senior Subordinated Notes due 2012 to change from a 7.25% fixed rate to a floating rate. The effect of the swap was to lower our overall effective interest rate on this debt from 7.25% to approximately 5.6% through November 1, 2004. On November 1, 2004 and every six months thereafter, the floating rate component will be locked in for six month periods at the then in effect six month London Interbank Offered Rate, or LIBOR, rate plus a margin of 2.345%. The decrease in interest expense related to Alliant 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 (IPO) in November 2003. A further explanation of the step-up transaction is included in the Liquidity and Capital Resources section below.

Income Tax Expense. We estimate that our effective income tax rate was 38.6% during the initial nine months of 2004, consistent with the yearly estimated effective tax rate for 2003. Prior to our IPO, we were included in the consolidated federal income tax return of Alliant Energy and calculated our income tax expense on a separate return basis at Alliant Energy s effective income tax rate. Immediately prior to our IPO, 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. As a result of this step-up in tax basis and the net operating loss generated during the post-IPO stub period in 2003, we currently expect to pay only a small amount of income taxes related to the 2004 tax year.

Cumulative Change in Accounting Principle. Effective January 1, 2003, we 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 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 well bores. 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 through charges to D,D&A. 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 $18.6 million during the initial nine months of 2003 to $37.4 million during the same period in 2004. The primary reasons for this increase included 20% higher crude oil and natural gas prices net of hedging between periods, 8.6% 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, offset by higher lease operating expense, general and administrative, DD&A, interest and exploration and impairment costs in 2004.

Year Ended December 31, 2003 Compared to Year Ended December 31, 2002

Oil and Natural Gas Sales. Oil and natural gas sales revenue increased approximately $53.0 million to $175.7 million in 2003. Natural gas sales increased $35.8 million and oil sales increased $17.2 million. The natural gas sales increase was caused by a 49% increase in the average realized natural gas price from $3.21 per Mcf in 2002 to $4.78 per Mcf in 2003 combined with a 230,000 Mcf volume increase in natural gas sales between years. The oil sales increase was caused by a sales volume increase of 275,000 Bbls in 2003 and an 18% increase in the average realized oil price from $23.35 in 2002 to $27.50 in 2003. The volume increase for oil and natural gas primarily resulted from the $217 million of capital expenditures during 2002 and 2003.

Loss on Oil and Natural Gas Hedging Activities. We hedged 41% of our natural gas volumes during 2003, incurring a hedging loss of $7.7 million, and 8% of our natural gas volumes during 2002, incurring a loss of $0.2 million. We hedged 8% of our oil volumes during 2003, incurring a hedging loss of $1.0 million, and 35% of our oil volumes during 2002, incurring a loss of $3.0 million.

Gain on Sale of Oil and Natural Gas Properties. In 2002, we divested one property, realizing a gain of $1.0 million. No significant properties were sold in 2003.

Lease Operating Expenses. Our lease operating expenses per Mcfe increased from $0.93 in 2002 to $1.16 in 2003. The increase resulted from acquisitions during 2002 that caused a larger portion of our operations to be located in Michigan and North Dakota, where weather conditions, sulfur content and remote locations create higher operating costs in comparison to other areas of operation.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 6.1% in 2003 and 6.0% in 2002. The small increase in the effective rate resulted from additional property purchases in the states of North Dakota and Montana, where effective production tax rates are higher on average than other areas where we own significant producing properties.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense decreased by $2.3 million in 2003. The decrease was a result of a decrease in the average rate from $1.24 per Mcfe in 2002 to $1.11 per Mcfe in 2003, partially offset by increased sales volumes in 2003. The lower rate was a result of higher prices between periods, which allowed for a longer economic production life and corresponding increased reserve volumes and, as a result, a lower depreciation, depletion and amortization rate.

Exploration Costs. Exploration costs increased $1.4 million to $3.2 million for 2003. The increase was the result of recording three exploratory dry holes during 2003 compared to one exploratory dry hole in 2002.

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General and Administrative Expenses. General and administrative expenses increased 6.9%, or $0.8 million, to $12.8 million in 2003. This increase was related to increases in compensation expense associated with increased personnel required to administer our growth and to general cost inflation.

Phantom Equity Plan Compensation. The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan. Under this plan, our employees received compensation of $10.9 million in the form of 420,000 shares of our common stock after withholding of shares by us for estimated payroll and income taxes. The phantom equity plan is now terminated.

Interest Expense. Interest expense decreased $1.7 million to $9.2 million in 2003 compared to $10.9 million in 2002. The decrease was due to lower average debt levels in 2003 and lower effective interest rates in 2003. The lower debt levels were primarily related to a March 2003 decision by Alliant Energy to convert its remaining $80.9 million of intercompany debt into our equity thereby lowering our future interest expense.

Income Tax Expense. Our effective tax rate was 38.6% in 2003 and 35.3% during 2002. The increased effective tax rate was in part due to our 2002 acquisitions in the state of North Dakota where the effective state income tax rate is higher on average than other areas where we own significant producing properties. In addition, during 2002 we generated $5.4 million of Section 29 credits that we were not able to offset against tax expense. Under our tax separation and indemnification agreement with Alliant Energy, we expect to be compensated for these credits in the future when they are utilized by Alliant Energy. Under generally accepted accounting principles, the recording of the tax credits in 2002 were required to be charged as additional paid-in capital rather than as a decrease to our 2002 income tax expense. Section 29 tax credit provisions of the Internal Revenue Code expired December 31, 2002. Therefore, unless additional legislation is passed, Section 29 credits will not be available in periods subsequent to 2002.

Cumulative Change in Accounting Principle. Effective January 1, 2003, we 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 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 well bores. 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 is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 7%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. 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 $7.7 million in 2002 to $18.3 million in 2003. The primary reasons for this increase included higher crude oil and natural gas prices between periods and higher volumes sold, offset by higher lease operating, tax and general and administrative costs due to our growth.

Year Ended December 31, 2002 Compared to Year Ended December 31, 2001

Oil and Natural Gas Sales. Oil and natural gas sales revenue decreased approximately $2.6 million to $122.7 million in 2002. Natural gas sales decreased $6.8 million, while oil sales increased $4.2 million. The natural gas sales decrease was caused by a 16% decline in the average realized natural gas price from $3.82 Mcf in 2001 to $3.21 Mcf in 2002, partially offset by an increase in natural gas production of 1.6 Bcf in

2002. The oil sales increase was caused by a sales volume increase of 200,000 Bbls in 2002, partially offset by a 2% decline in the average realized oil price from $23.85 in 2001 to $23.35 in 2002. The volume increase for oil and natural gas was due to $265 million of capital expenditures during 2001 and 2002.

Loss on Oil and Natural Gas Hedging Activities. We hedged 8% of our natural gas volumes during 2002, incurring a hedging loss of $0.2 million, and 11% of our natural gas volumes during 2001, incurring a gain of $1.6 million. We hedged 35% of our oil volumes during 2002, incurring a hedging loss of $3.0 million, and 17% of our oil volumes during 2001, incurring a gain of $0.7 million.

Gain on Sale of Oil and Natural Gas Properties. In 2002, we divested only one property, realizing a gain of $1.0 million, while in 2001, we divested several properties, realizing total sales gains of $11.7 million.

Lease Operating Expenses. Our lease operating expenses per Mcfe increased from $0.92 in 2001 to $0.93 in 2002. The increase resulted from acquisitions during 2002 that caused a larger portion of our operations to be located in Michigan and North Dakota, where weather conditions, sulfur content and remote locations create higher operating costs.

Production Taxes. Production taxes as a percentage of oil and natural gas sales were 6.0% in 2002 and 5.2% in 2001. The increase in the effective rate resulted from additional property purchases in the states of North Dakota and Montana, where effective production tax rates are higher on average than other areas where we own significant producing properties.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense in 2001 included a $9.0 million reduction related to the asset retirement obligations for the Point Arguello platform located offshore from California. During 2001, we received a revised and more detailed dismantlement plan from the operator. The $9.0 million reduction of liability was credited against depreciation, depletion and amortization expense since the liability was initially created by charges to depreciation, depletion and amortization expense. Without this credit, our depreciation, depletion and amortization expense charge for 2001 would have been $35.9 million. The increase to $43.6 million of depreciation, depletion and amortization expense in 2002 was a result of increasing sales volumes and an increased rate from $1.11 per Mcfe in 2001 to $1.24 per Mcfe in 2002.

Exploration Costs. Exploration costs increased $1.0 million to $1.8 million for 2002 compared with $0.8 million for 2001. The increase was partially the result of a $420,000 charge for an exploratory dry hole in 2002. The remaining increase in 2002 is related to the further development and processing of our geophysical library.

General and Administrative Expenses. General and administrative expenses increased 9.5% or $1.1 million from $10.9 million in 2001 to $12.0 million in 2002. This increase was related to increases in compensation expense associated with increased personnel required to administer our growth and to general cost inflation.

Interest Expense. Interest expense increased $0.7 million to $10.9 million in 2002 compared to $10.2 million in 2001. The increase was due to higher average debt levels in 2002 to fund our growth, partially offset by a lower effective interest rate.

Income Tax Expense. Our effective tax rate before tax credits was 36.8% in 2002 and 36.2% in 2001. In 2001, we were able to reduce our tax expense by $6.6 million due to the recording of Section 29 tax credits. In 2002, we generated $5.4 million of Section 29 credits that we were not able to offset against tax expense. Under our tax separation and indemnification agreement with Alliant Energy, we expect to be compensated for these credits in the future when they are utilized by Alliant Energy. Under generally accepted accounting principles, the recording of the tax credits in 2002 were required to be charged as additional paid-in capital rather than as a decrease to our 2002 income tax expense. Section 29 tax credit provisions of the Internal Revenue Code expired December 31, 2002. Therefore, unless additional legislation is passed, Section 29 credits will not be available in periods subsequent to 2002.

Net Income. Net income decreased from $41.2 million in 2001 to $7.7 million in 2002. The primary reasons were a $19.0 million decline in revenues, a $23.5 million increase in expenses and the inability to recognize $5.4 million of tax credits as a reduction of tax expense. The revenue decrease was caused by a decline in oil and

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natural gas prices between years and $10.7 million less gains from the sales of properties in 2002. The expense increase was caused by the $9.0 million reduction to 2001 depreciation, depletion and amortization related to the adjustment of the Point Arguello asset retirement obligations and cost increases in all other categories to operate and administer the property acquisitions during 2001 and 2002.

Liquidity and Capital Resources

Overview. We entered 2004 with $53.6 million of cash and cash equivalents. During the first nine months of 2004, we generated an additional $96.9 million from operating activities. On February 17, 2004, we used $40.0 million of our cash to pay down $40.0 million of the outstanding principal balance under our bank credit facility. On May 11, 2004, we used the proceeds from the issuance of our 7 1/4% Senior Subordinated Notes due 2012 to repay the remaining $145 million of outstanding principal under our credit facility. At September 30, 2004, our debt to total capitalization ratio was 63.7%, we had $17.4 million of cash on hand and $334.9 million of stockholders equity.

We continually evaluate our capital needs and compare them to our capital resources. Our budgeted capital expenditures for the further development of our property base are $80.0 million during 2004, an increase from the $40.3 million spent on capitalized development during 2003. During the first nine months of 2004, we spent $52.8 million on development, which was a 102% increase from the $26.2 million spent on development during the first nine months of 2003. We also spent $445.3 million on acquisitions, funded primarily by borrowings under our credit facility, all in the third quarter of 2004. Although we have no specific budget for property acquisitions, we will continue to seek property acquisition opportunities that complement our existing core property base. We expect to fund the remainder of our 2004 development expenditures from internally generated cash flow and cash on hand. We believe that should attractive acquisition opportunities arise or development expenditures exceed $80.0 million, we could finance the additional capital expenditures with cash on hand, operating cash flow, borrowings under Whiting Oil and Gas Corporation s credit agreement, issuances of additional equity or development 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 Facility. On September 23, 2004, Whiting Oil and Gas Corporation entered into an amended and restated $750.0 million credit agreement with a syndicate of banks. The new credit agreement increases our borrowing base to $480.0 million from $195.0 million under the prior credit agreement. The borrowing base under the credit agreement is determined in the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders and is subject to regular redetermination on May 1 and November 1 of each year as well as special redeterminations described in the credit agreement. On September 23, 2004, Whiting Oil and Gas Corporation borrowed $400.0 million under the credit agreement in order to (i) refinance the entire outstanding balance under the prior credit agreement and (ii) fund its $345.0 million acquisition of oil and natural gas producing properties in the Permian Basin. On September 30, 2004, we borrowed an additional $35.0 million to fund an additional acquisition.

The credit agreement provides for interest only payments until September 23, 2008, when the entire amount borrowed is due. In addition, the credit agreement provides that Whiting Oil and Gas Corporation will make principal payments under the credit agreement by May 1, 2005 to reduce the principal balance to $385.0 million. Whiting Oil and Gas Corporation may, throughout the four year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect from time to time. 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 federal funds rate plus 0.5% or the prime rate and the margin varies from 0% to 0.50% 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 0.250% 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.

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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, change material contracts, 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 of greater than 1 to 1. The credit agreement also requires us to hedge at least 60%, but not more than 75%, of our total forecasted PDP production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps, with a minimum floor price of $35 per barrel of oil or $4.50 per MMbtu. After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to a maximum of 75% of our forecasted PDP production. In addition, while the credit agreement allows our subsidiaries to make payments to us so that we may pay interest on our senior subordinated notes, it does not allow our subsidiaries to make payments to us to pay principal on the senior subordinated notes. We were in compliance with our covenants under the credit agreement as of September 30, 2004. The credit agreement is secured by a first lien on substantially all of Whiting Oil and Gas Corporation s assets. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement, Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for its guarantee and Equity Oil Company has mortgaged substantially all of its assets as security for its guarantee.

7 1/4% Senior Subordinated Notes due 2012. On May 11, 2004, we issued, in a private placement, $150.0 million aggregate principal amount of our 7 1/4% senior subordinated notes due 2012. The net proceeds of the offering were used to retire all of our debt outstanding under Whiting Oil and Gas Corporation s credit agreement. The notes were issued at 99.26% of par and the associated discount is being amortized to interest expense over the term of the notes. On July 12, 2004, we completed an exchange offer in which we issued $150.0 million aggregate principal amount of new 7 1/4% senior subordinated notes due 2012 registered under the Securities Act of 1933 in exchange for the old notes. The notes are unsecured obligations of ours and are subordinated to all of our senior debt. The indenture governing the notes contains 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 us 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. We were in compliance with these covenants as of September 30, 2004. 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.

Alliant Energy Promissory Note. In conjunction with our initial public offering in November 2003, we 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%. All principal and interest on the promissory note are due 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 basis of our assets. This additional basis is 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 basis 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 basis 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.

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Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of September 30, 2004 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 interest expense since we cannot determine with accuracy the timing of future loan advances and repayments and the future interest rate to be charged under floating rate instruments. During August 2004, we entered into an interest rate swap on $75.0 million of our $150.0 million fixed rate 7 1/4% senior subordinated notes due 2012. The amount of interest we expect to pay relating to the $75.0 million of our senior subordinated notes remaining under the 7 1/4% fixed rate is $1.4 million during the last three months of 2004, then $5.4 million annually through the term of the notes.

	Payments due by period				
Contractual Obligations	Total	Less than 1 year	1-3 years	3-5 years	More than 5 years
Long-Term Debt	$ 588.8	$ 50.0	$ 3.1	$ 385.0	$ 150.7
Operating Lease	5.7	0.9	1.8	1.8	1.2
Tax Separation and Indemnification Agreement with Alliant Energy(1)	30.6		4.2	3.1	23.3
Total	$ 625.1	$ 50.9	$ 9.1	$ 389.9	$ 175.2

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

Off-Balance Sheet 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, 2004 increased to 50% of the actual price received in excess of $19.77 per barrel. As of September 30, 2004, approximately 45,800 net barrels of crude oil per month (10% of October 2004 estimated 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. As of September 30, 2004, we have paid $6.1 million under this agreement and we have accrued an additional $427,000 as currently payable.

New Accounting Policies

In June 2001, the Financial Accounting Standards Board, or the FASB, issued SFAS No. 141, Business Combinations, which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, Goodwill and Other Intangible Assets, which discontinues the practice of amortizing goodwill and indefinite-lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The amortization provisions apply to goodwill and intangible assets acquired after June 30, 2001. In March 2004, the Emerging Issues Task Force, or the EITF, reached a consensus that mineral rights, as defined in EITF Issue No. 04-02, Whether Mineral Rights Are Tangible Or Intangible Assets, are tangible assets and that they should be removed as examples of intangible assets in SFAS Nos. 141 and 142. The FASB has recently ratified this consensus and directed the FASB staff to amend SFAS Nos. 141 and 142 through the issuance of FASB Staff Position, or FSP, FAS Nos. 141-1 and 142-1. In addition, proposed FSP 142-b confirms that SFAS No. 142 does not change the balance sheet classification or disclosures of mineral rights of oil and gas producing enterprises. Historically, we have included the costs of such mineral rights as tangible assets, which is consistent with the EITF s consensus. As such, EITF 04-02 and the related FSPs have not affected our consolidated financial statements.

Effective January 1, 2003, we 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

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assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 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. In regards to us, this statement applies directly to the plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 7%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. 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). We have an additional $4.3 million asset retirement obligations relating to our retained obligation with respect to the Point Arguello facility located offshore from California.

FASB Interpretation No. 45, or FIN 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others was issued in November 2002 by the FASB. FIN 45 requires a guarantor to recognize a liability for the fair value of the obligation it assumes under certain guarantees. Additionally, FIN 45 requires a guarantor to disclose certain aspects of each guarantee, or each group of similar guarantees, including the nature of the guarantee, the maximum exposure under the guarantee, the current carrying amount of any liability for the guarantee, and any recourse provisions allowing the guarantor to recover from third parties any amounts paid under the guarantee. The disclosure provisions of FIN 45 are effective for financial statements for both interim and annual periods ending after December 15, 2002. The fair value measurement provisions of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The adoption of this statement did not have a material impact on our financial statements.

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 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. Our crude oil and natural gas hedges are designed to be treated as cash flow hedges under Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activity. This policy is significant since it impacts the timing of revenue recognition. Under this pronouncement, the majority of our hedging gains or losses are recorded in the month the contracts settle. We reflect this as an adjustment to revenue through the Gain (loss) on oil and gas hedging activities line item in our consolidated income statements. If our hedges did not qualify for cash flow hedge treatment, then our consolidated income statements could include large non-cash fluctuations in this line item, particularly in volatile pricing environments, as our contracts are marked to their period end market values.

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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 acquisition, 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. All of our properties are located within the continental United States and the Gulf of Mexico.

Oil and Natural Gas Reserve Quantities. Reserve quantities and the related estimates of future net cash flows affect our periodic calculations of depletion and impairment of our oil and natural gas properties. 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 prospectus 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 prospectus is based on estimates prepared by Ryder Scott Company, Cawley, Gillespie & Associates, Inc. and R.A. Lenser & Associates, Inc., each independent petroleum engineers, and Whiting Oil and Gas Corporation s engineering staff. The independent petroleum engineers evaluated approximately 83% of the pre-tax PV10% value of our proved reserves as of December 31, 2003 and Whiting Oil and Gas Corporation s engineering staff evaluated the remainder. 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 and impairment calculations in the same period that changes to the reserve estimates are made.

Impairment of Oil and Natural 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 proved producing properties are calculated by comparing future net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded book cost 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.

Income Taxes. We provide for income taxes in accordance with Statement of Financial Accounting Standards No. 109, Accounting for Income Taxes. Deferred income taxes are provided for the difference between the tax basis of assets and liabilities and the carrying amount in our financial statements. This difference will result in taxable income or deductions in future years when the reported amount of the asset or liability is settled. Since our tax returns are filed after the financial statements are prepared, estimates are required in valuing tax assets and liabilities. We record adjustments to actual in the period we file our tax returns.

Effects of Inflation and Pricing

We experienced increased costs during 2001, 2002 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 impact the current revenue stream, estimates of future reserves, borrowing base calculations of bank loans and value 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 cost of material, services and personnel.

Quantitative and Qualitative Disclosures 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 December 2003 production, our income before income taxes moves approximately $2.1 million for every $0.10 change in natural gas prices and approximately $2.4 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 with no-cost 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 on the consolidated balance sheet. Recognition in the consolidated income statement occurs in the period of contract settlement. Our credit agreement requires us to hedge at least 60%, but not more than 75%, of our total forecasted PDP production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps with a minimum floor price of $35 per barrel of oil or $4.50 per MMbtu. After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to a maximum of 75% of our forecasted PDP production. We also seek to diversify our hedge position with various counterparties where we have clear indications of their current financial strength.

Our outstanding hedges as of October 28, 2004 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)/(Bbl)	NYMEX Floor/Ceiling
Natural Gas	10/2004 to 12/2004	400,000	4.50/9.40
Natural Gas	10/2004 to 12/2004	400,000	4.50/12.00
Natural Gas	10/2004 to 12/2004	650,000	4.50/8.75
Natural Gas	01/2005 to 03/2005	400,000	5.00/12.75
Natural Gas	01/2005 to 03/2005	500,000	5.00/11.00
Natural Gas	01/2005 to 03/2005	600,000	5.00/10.50
Natural Gas	04/2005 to 06/2005	1,500,000	4.50/8.25
Natural Gas	07/2005 to 09/2005	1,500,000	4.50/8.60
Natural Gas	10/2005 to 12/2005	1,500,000	4.50/10.00
Crude Oil	10/2004 to 12/2004	50,000	28.00/46.10
Crude Oil	10/2004 to 12/2004	50,000	30.00/48.50

Crude Oil	10/2004 to 12/2004	44,000	35.00/51.90
Crude Oil	10/2004 to 12/2004	120,000	37.00/49.10
Crude Oil	10/2004 to 12/2004	50,000	37.00/54.75
Crude Oil	01/2005 to 03/2005	50,000	35.00/50.75
Crude Oil	01/2005 to 03/2005	94,000	35.00/49.60
Crude Oil	01/2005 to 03/2005	120,000	37.00/46.90
Crude Oil	01/2005 to 03/2005	80,000	37.00/50.60
Crude Oil	04/2005 to 06/2005	250,000	37.00/46.65
Crude Oil	07/2005 to 09/2005	250,000	35.00/47.25
Crude Oil	10/2005 to 12/2005	125,000	35.00/60.55
Crude Oil	10/2005 to 12/2005	125,000	35.00/65.75

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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 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 of $145,000 for the remainder of 2004. For the 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 of $314,000 for the remainder of 2004.

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 October 28, 2004 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	2004 Price Per MMBtu
Natural Gas	01/2002 to 12/2011	51,000	$ 4.22
Natural Gas	01/2002 to 12/2012	60,000	$ 3.74

The table below summarizes the hedges and fixed price marketing contracts described above:

Hedges and Contracts Summary	Hedged and Contracted (MMBtu)/(Bbl) per Month	As a Percentage of Estimated October 2004 Production (Gas/Oil)
October December 2004	1,561,000/314,000	60%/69%
January March 2005	1,611,000/344,000	62%/75%
April June 2005	1,611,000/250,000	62%/55%
July September 2005	1,611,000/250,000	62%/55%
October December 2005	1,611,000/250,000	62%/55%
Thereafter	111,000/-0-	4%/-0-

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 facility. The credit facility 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 facility 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 September 30, 2004, our outstanding principal balance under our credit facility was $435.0 million and the interest rate on the entire outstanding principal balance was fixed at 3.34% through October 28, 2005. At September 30, 2004, the carrying amount approximated fair market value. Assuming a constant debt level of $588.8 million, the cash flow impact for 2004 resulting from a 100 basis point change in interest rates during periods when the interest rate is not fixed would be $907,000.

Interest Rate Swap

In August 2004, we entered into an interest rate swap contract to hedge the fair value of $75 million of our 7 1/4% 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 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 million for the six month period. As of September 30, 2004, we have recorded a long term derivative asset of $1.7 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding debt increase.

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BUSINESS AND PROPERTIES

About Our Company

We are engaged in oil and natural gas exploitation, acquisition, exploration and production activities primarily in the Rocky Mountains, Permian Basin, Gulf Coast, Michigan, Mid-Continent and California regions of the United States. Our focus is on pursuing growth projects that we believe will generate attractive rates of return and maintaining a balanced portfolio of lower risk, long-lived oil and natural gas properties that provide stable cash flows.

Since our inception in 1980, we have built a strong asset base and achieved steady growth through both property acquisitions and exploitation activities. As of January 1, 2004, our estimated proved reserves totaled 438.8 Bcfe, of which 75% were classified as proved developed. These estimated reserves had a pre-tax PV10% value of approximately $784.6 million, of which approximately 85% came from properties located in three states: Texas, North Dakota and Michigan. During 2003, we spent approximately $52.0 million on capital projects, including $38.8 million for the drilling of 72 gross (24.8 net) wells (64 successful completions and eight uneconomic wells), representing an 89% success rate. We have budgeted approximately $80.0 million for capital expenditures in 2004. Through September 30, 2004, we have invested $52.8 million of our budgeted expenditures for the drilling of 116 gross (49.7 net) wells with 108 successful completions and eight uneconomic wells, representing a 93% success rate.

As of January 1, 2004, we had a balanced portfolio of oil and natural gas reserves, with approximately 53% of our proved reserves consisting of natural gas and approximately 47% consisting of oil. Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of proved reserves to trailing 12 month production ending December 31, 2003 of approximately 11.8 years.

During 2004, we completed five separate acquisitions of producing properties with a combined purchase price of $516.1 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 421.9 Bcfe, representing an average cost of approximately $1.22 per Mcfe of estimated proved reserves. We will continue to seek property acquisition opportunities that complement our existing core properties. We believe that our exploitation and acquisition expertise and our drilling inventory, together with our operating experience and efficient cost structure, provide us with the potential to continue our growth.

As of October 1, 2004, which includes the impact of these five acquisitions, our estimated proved reserves totaled 867.3 Bcfe, representing a 98% increase in proved reserves since January 1, 2004. Natural gas made up 39.0% of total proved reserves and 72% were classified as proved developed. Of these reserves, 38.8% were located in the Rocky Mountain region, 31.6% in the Permian Basin, 13.4% in the Gulf Coast, 11.4% in Michigan, 3.2% in the Mid-Continent region and 1.6% in California. Our estimated October 2004 average daily production is 177.7 MMcfe, representing a 75% increase over December 2003 average daily production and implying an average reserve life of approximately 13.4 years.

The following table summarizes our estimated proved reserves and pre-tax PV10% value within our core areas as of October 1, 2004 and our estimated October 2004 average daily production, each of which includes the impact of these five acquisitions.

	Proved Reserves	October 2004

Core Area	Oil (MMbbl)	Natural Gas (Bcf)	Total (Bcfe)	% Natural Gas	Pre-Tax PV10% Value (In millions)		Average Daily Production (MMcfe)
Permian Basin	37.7	47.9	274.2	17.5%	$	731.5	41.4
Rocky Mountains[1]	43.3	76.3	336.4	22.7%	$	716.1	65.1
Gulf Coast	3.3	96.2	115.8	83.0%	$	324.2	39.2
Michigan	1.9	87.8	99.1	88.6%	$	219.1	21.0
Mid-Continent	2.0	15.7	27.9	56.4%	$	61.8	6.2
California	0.0	14.0	14.0	100.0%	$	35.2	4.9
Total	88.2	337.9	867.3	39.0%	$	2,087.9	177.7

(1) Includes one field in Canada with total estimated proved reserves of 5.2 Bcfe and a pre-tax PV10% value of $14.0 million.

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Recent Acquisitions

The following table summarizes certain information about the purchase price, estimated proved reserves and pre-tax PV10% value as of October 1, 2004 and estimated October 2004 average daily production for the five recent acquisitions described below.

	Purchase Price (In millions)	Proved Reserves: Oil (MMbbl)	Proved Reserves: Natural Gas (Bcf)	Proved Reserves: Total (Bcfe)	Proved Reserves: % Natural Gas	Proved Reserves: % Developed	Proved Reserves: Pre-Tax PV 10% Value (In millions)[6]	October 2004 Average Daily Production (MMcfe)
Permian Basin[1] Properties	$ 345.0	34.2	44.6	250.0	17.8%	59%	$ 673.6	36.4
Equity Oil Company[2]	$ 72.6	10.2	42.1	103.6	40.6%	69%	$ 217.6	16.1
Colorado/ Wyoming[3]	$ 44.2	3.4	19.4	40.1	48.4%	82%	$ 76.6	8.6
Wyoming/Utah[4]	$ 35.0	3.6	11.1	32.6	34.1%	92%	$ 64.5	6.1
Louisiana/Texas[5]	$ 19.3	0.5	10.7	13.9	76.9%	57%	$ 39.5	3.5
Subtotal Acquisitions	$ 516.1	52.0	127.9	440.1	29.1%	66%	$ 1,071.8	70.7
Whiting Historical		36.2	210.0	427.2	49.2%	78%	$ 1,016.1	107.0
Total		88.2	337.9	867.3	39.0%	72%	$ 2,087.9	177.7

(1) Proved reserves are based on the reserve report prepared by Cawley, Gillespie & Associates, Inc., independent petroleum engineers, as of July 1, 2004. Revenues and volumes are included in our results beginning September 23, 2004.

(2) Proved reserves are based on the reserve report prepared by Ryder Scott Company, L.P., independent petroleum engineers, as of December 31, 2003. Equity s results of operations and volumes are included in our results beginning July 20, 2004.

(3) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning August 13, 2004.

(4) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning September 30, 2004.

(5) Proved reserves are based on reserve reports prepared by our engineering staff. Revenues and volumes are included in our results beginning August 16, 2004.

(6) These amounts were calculated using a period end average realized oil price of $45.87 per barrel and a period end average realized natural gas price of $5.64 per Mcf.

Permian Basin Properties

On September 23, 2004, we 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 our bank credit agreement.

For the year ended December 31, 2003, these properties reported revenues in excess of direct operating expenses of $72.1 million. As of October 1, 2004, these properties had 250.0 Bcfe of estimated proved reserves, of which 17.8% were natural gas and 59% were classified as proved developed, and had a pre-tax PV10 value of estimated proved reserves of $673.6 million. The estimated October 2004 average daily production for these properties is approximately 36.4 MMcfe, implying an average reserve life of 18.8 years. We operate approximately 72% of the average daily production from these properties.

Low Cost Acquisition in Core Operational Area. Based on the purchase price of $345.0 million and estimated proved reserves of 251.6 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.37 per Mcfe of estimated proved reserves. We added approximately 300 operated producing wells in our Permian Basin core area with this acquisition.

Attractive Operating Cost Profile. The acquired Permian Basin properties operating performance is characterized by low operating costs. This acquisition was also attractive because average lease operating expense for these properties over the past three years was $0.68 per Mcfe in contrast to our historical lease operating expense of $1.01 per Mcfe for the same period. Additionally, we expect the anticipated incremental general and administrative expense for these properties to be lower than that of our existing operations given its overlap with our current operations in the Permian Basin. Including the impact of this acquisition, our Permian Basin region is now nearly as large as our Rocky Mountains core area, representing 31.6% and 38.8% of our total proved reserves as of October 1, 2004, respectively.

Additional Development Opportunities. We expect to leverage our operational and technical expertise in this core area to fully exploit the potential these properties present. We plan to continue the development of the PUD and other non-producing reserves we have acquired through this acquisition, and believe that this development offers us the opportunity to increase the current rate of production.

The following is a summary description our interests and activities in the five key fields identified above. Except where indicated, production numbers are as of September 30, 2004.

Parkway (Delaware) Unit. We own a 62% non-operated working interest (52% net interest) in the Parkway (Delaware) Unit, which is concentrated on 921 gross acres in Eddy County, New Mexico. September 2004 production averaged 1,782 bopd and 1,233 Mcf/d of natural gas (926 bopd, 641 Mcf/d, net). The first two wells of an ongoing infill program added over 500 bopd of new production. Wells are being drilled to convert the five spot flood pattern to a nine spot pattern. We have identified 17 PUD locations in this unit.

Would Have Field. We own a 75% operated working interest in the Would Have Field in Howard County, Texas, with a net production of 693 bopd and 496 Mcf/d of natural gas from 49 wells. Discovered in 2001 and covering over 13,000 gross acres, this field produces from two sub-units of the Clearfork Formation, the Would Have and the Dillard Limestones. A waterflood was initiated in the western half of the field in May 2004 and efforts are underway to expand the flood to the eastern portion of the field. The Would Have property is covered by proprietary 3-D seismic data. We believe that utilization of this 3-D dataset has led to the efficient development and delineation of the Would Have field. The Would Have Field is only partially developed, with both infill and step-out locations remaining to be drilled.

Signal Peak Field. Our Signal Peak property currently adds 168 bopd and 3.5 MMcf/d of natural gas from our operated wells. We own an average working interest of 72% in the property, of which we operate approximately 75%. The primary producing horizon in the Signal Peak Field is the Wolfcamp reservoir, with behind pipe Clearfork potential identified in several wells.

Keystone Field. Our 100% working interest in the Keystone Field provides both substantial production (561 bopd and 2.0 Mcf/d of natural gas) and a large portfolio of additional exploration and development opportunities. The property covers a surface area of 7,261 acres in Winkler County, Texas. Most current production comes from the Clearfork, although additional producing zones include the Wichita-Albany, Wolfcamp, Devonian, Silurian, McKee and Ellenburger. As a result of its multi-zone nature, many wells in the property contain several intervals of pay resulting in numerous behind-pipe recompletion opportunities. Most of the Keystone Field is covered by 3-D seismic data that has been used to make several discoveries, and we believe that drilling potential remains throughout this property. We have identified 20 PUD locations throughout the property.

DEB Field. We own a 100% working interest in the DEB Field that covers 738 acres in Gaines County, Texas and produces 723 bopd and 75 Mcf/d of solution gas from nine wells. The Wolfcamp reservoir is subdivided into two productive intervals, the A and the B, that both produce and are commingled in several wells. Current injection into the Wolfcamp is approximately 15,000 barrels of water per day and oil production in this long-life property has remained relatively flat for many years. Modifications have recently been completed increasing the fluid handling capability of the facilities. This will allow submersible pumps with increased capacity to be installed.

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Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our 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.

For the year ended December 31, 2003, Equity reported income from continuing operations of $2.4 million, net cash provided by operating activities of $11.5 million and production of 6.6 Bcfe (45% natural gas). As of October 1, 2004, Equity had 103.6 Bcfe of estimated proved reserves, of which 40.6% were natural gas and 69% were classified as proved developed, and had a pre-tax PV10% value of estimated proved reserves of approximately $217.6 million. The estimated October 2004 average daily production from these properties is approximately 16.1 MMcfe, implying an average reserve life of 17.6 years.

Based on the purchase price of $72.6 million and estimated proved reserves of 87.7 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $0.83 per Mcfe of estimated proved reserves.

Addition of Long-life, Stable Reserves. With a reserve life index of over 17 years, the long-life Equity reserves are predominately in mature and predictable fields.

Expansion of Exploration and Exploitation Opportunities. With over 75,000 net undeveloped acres and 375 square miles of 3-D seismic, the Equity properties have added to our inventory of exploration, development and exploitation opportunities. We expect our strong financial position to allow more rapid development of these opportunities than Equity s cash flow permitted.

Creates Synergies and Cost Savings. We anticipate that combining the complementary operations of the two companies will allow us to take advantage of synergies and to realize cost savings.

The following is a summary description our interests and activities in Equity s properties.

Big Horn Basin. The Big Horn Basin of northwestern Wyoming has been a focus area for Equity since 1997. Big Horn Basin properties are typically long-lived high water cut oil fields, which benefit from our expertise in lift optimization and polymer injection technology to reduce water production. We operate 114 wells in the basin, producing just under 800 Boe per day. Our working interests in these wells range from 30% to 100%. The most significant asset in the Big Horn Basin is the Torchlight Field where we own a 100% working interest. During 2003 Equity completed several successful water shut-off treatments utilizing a polymer treatment developed by Marthon Oil Company. Five additional water shut-off treatments were performed during 2004. As a result, average monthly production during 2004 has been 8,617 barrels per month, which is 6% higher than the 2003 rate of 8,144 barrels per month. We plan to continue to utilize the water shut-off technology to increase production.

Williston Basin. During July 2003, Equity completed the #23-3 BR as the discovery well in the Roosevelt Creek Prospect in Golden Valley County, North Dakota. The #23-3 flowed 142 barrels of oil per day from the Nisku Formation at approximately 10,754 to 10,758 feet. Equity completed a stepout horizontal confirmation well, #11-10 Schieffer, pumping 117 barrels of oil per day, in December 2003. We are a 25% working interest owner in both wells. We have acquired 63 square miles of proprietary 3-D seismic data in the Roosevelt Creek and adjacent Beaver Creek Prospect areas where these two wells were drilled, and have identified drilling opportunities targeting oil in the Bakken, Nisku and Red River Formations. The Roosevelt Creek Prospect that Equity had developed is directly adjacent to the Nisku A project Whiting was pursuing. Additional information on this project follows. Our year-end independent reserve evaluation from Ryder Scott Company, L.P. included sixteen proved undeveloped drilling locations in these Prospect areas.

Green River Basin Siberia Ridge. Equity owned working interests ranging from 40% to 100% in 5,730 gross acres (3,177 net) in Sweetwater County, Wyoming. Most of this acreage was developed with four to five wells per section. Production is from the Almond Formation at a depth of approximately 10,000 feet. In 2004, the Wyoming Oil and Gas Conservation Commission amended the existing spacing rules to allow up to 8 wells per section. As a result of this spacing change, there are 42 additional legal locations on the Equity acreage. Permitting efforts on the first 15 wells has been initiated and drilling is forecast to begin mid-2005.

Sacramento Basin. Effective January 1, 2002, Equity purchased an operated working interest in 27 producing gas wells and associated leasehold primarily in the Todhunters Lake and Willow Slough Fields of Yolo County, California. The acquisition included proved developed producing reserves, proved developed behind pipe recompletion opportunities and several drilling opportunities. During July 2003, Equity completed three development wells in the Todhunters Lake Field, where we maintain a 100% working interest. An active recompletion program has been undertaken since assuming operation of these properties to maintain production. During September 2004 production from the operated wells averaged 3.6 million cubic feet per day.

Other Cash Acquisitions of Properties

Colorado and Wyoming Properties. On August 13, 2004, we acquired interests in four producing oil and gas fields in Colorado and Wyoming from an undisclosed seller. The purchase price was $44.2 million in cash and was funded under our bank credit agreement. We operate two of the fields and have an 84% average working interest in those fields. As of October 1, 2004, these interests had 40.1 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 8.6 MMcfe, implying an average reserve life of 12.7 years. Based on the purchase price of $44.2 million and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.11 per Mcfe of estimated proved reserves.

One of the acquired fields, Hiawatha West, located in Moffat County, Colorado contains additional drilling opportunities. Four permitted well locations exist in the field, and we are in the process of locating equipment and contracting rigs to allow the drilling of these wells. An additional four proved undeveloped locations exist in the field.

Wyoming and Utah Properties. On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah from an undisclosed seller. The purchase price was $35.0 million in cash and was funded under our bank credit agreement. As of October 1, 2004, these interests had 32.6 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 6.1 MMcfe, implying an average reserve life of 14.7 years. Based on the purchase price of $35.0 million and estimated proved reserves of 30.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.14 per Mcfe of estimated proved reserves.

Louisiana and South Texas Properties. On August 16, 2004, we acquired interests in five fields in Louisiana and South Texas from Delta Petroleum Corporation. The purchase price was $19.3 million in cash and was funded under our bank credit agreement. We operate two of the fields and have a 93% average working interest in those fields. As of October 1, 2004, these interests had 13.9 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 3.5 MMcfe, implying an average reserve life of 11.0 years. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.61 per Mcfe of estimated proved reserves.

Business Strategy

Our goal is to increase stockholder value by investing in oil and gas projects with attractive rates of return on capital employed. We plan to achieve this goal by exploiting and developing our existing oil and natural gas properties and pursuing acquisitions of additional properties. Specifically, we have focused, and plan to continue to focus, on the following:

Developing and Exploiting Existing Properties. We believe that there is significant value to be created by drilling the numerous identified undeveloped opportunities on our properties. As of January 1, 2004, we owned

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interests in a total of 517,000 gross (206,000 net) developed acres. In addition, as of December 31, 2003, we owned interests in approximately 386,000 gross (188,000 net) undeveloped acres that contain many exploitation opportunities. During the three years ended December 31, 2003, we invested $94 million to participate in the drilling of 169 gross (60.6 net) wells, the majority of which were developmental wells, and 85.2% were successful completions. As of January 1, 2004, we had identified a total of 171 proved undeveloped drilling locations on our properties. We drilled or participated in the drilling of 72 gross (24.8 net) wells during the year ended December 31, 2003 and have budgeted approximately $80.0 million for the further development of our properties in 2004. Through September 30, 2004, we have invested $52.8 million of our budgeted expenditures for the drilling of 116 gross (49.7 net) wells with 108 successful completions and eight uneconomic wells, representing a 93% success rate.

Pursuing Profitable Acquisitions. We have pursued and intend to continue to pursue acquisitions of properties that we believe to have exploitation and development potential comparable to our existing inventory of drilling locations. We have developed and refined an acquisition program designed to increase reserves and complement our existing core properties. We have an experienced team of management, engineering and geoscience professionals who identify and evaluate acquisition opportunities, negotiate and close purchases and manage acquired properties. During the first nine months of 2004, we completed five separate acquisitions of producing properties with a combined purchase price of $516.1 million for estimated proved reserves as of the effective dates of the acquisitions of approximately 421.9 Bcfe, representing a cost of $1.22 per Mcfe of estimated proved reserves. To secure attractive realized commodity prices on a portion of our volumes, we periodically enter into derivative contracts, typically no-cost collars. Given our recent acquisitions discussed above, and as an additional step toward realizing our profit potential from these acquisitions, we have increased our volumes subject to these collars to cover approximately 56% to 58% (excluding fixed price marketing contracts) of our natural gas volumes as of October 1, 2004 through December 2005 and between 55% and 75% of our crude oil volumes as of October 1, 2004 through December 2005. The average floor and ceiling for these volumes are approximately $4.60 and $9.59 per Mcf of natural gas, respectively, and $35.45 and $50.98 per bbl of crude oil, respectively.

Focusing on High Return Operated and Non Operated Properties. 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 complemented our existing operations. We intend to continue to acquire both operated and non operated interests to the extent they meet our return criteria and further our growth strategy.

Controlling Costs through Efficient Operation of Existing Properties. We operate approximately 60% of the pre-tax PV10% value of our total proved reserves and approximately 82% of the pre-tax PV10% value of our proved undeveloped reserves, which we believe enables us to better manage expenses, capital allocation and the decision making processes related to our exploitation and exploration activities. For the year ended December 31, 2003, our lease operating expense per Mcfe averaged $1.16 and general and administrative costs averaged $0.34 per Mcfe produced, net of reimbursements.

Competitive Strengths

We believe that our key competitive strengths lie in our diversified asset base, our experienced management and technical team and our commitment to efficient utilization of new technologies.

Diversified Asset Base. As of January 1, 2004, we had interests in 5,006 wells in 16 states across our four core geographical areas of the United States. This property base, as well as our continuing business strategy of acquiring and developing properties in our core operating areas, presents us with a large number of opportunities for successful development and exploitation and additional acquisitions.

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Experienced Management Team. Our management team averages 27 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 20 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 575 square miles of 3-D seismic data that we have assembled primarily over the past five years. A team with access to state of the art geophysical/geological computer applications and hardware analyzes this information. Computer applications, such as the WellView® software system, 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 technology and expertise has greatly aided our pursuit of attractive development projects.

Proved Reserves

Our proved reserves as of January 1, 2004 are summarized in the table below.

	Oil (MBbl)	Natural Gas (MMcf)	Total (Bcfe)	% of Total Proved	Pre-tax PV10% (In thousands)	Future Capital Expenditures (In thousands)
Gulf Coast/Permian Basin:						
PDP	4,300	52,322	78.1	17.8%	$ 172,347	$ 2,784
PDNP	287	6,232	8.0	1.8%	20,465	1,141
PUD	939	30,856	36.4	8.3%	73,933	25,794
Total Proved:	5,526	89,410	122.5	27.9%	$ 266,745	$ 29,719
Rocky Mountains:						
PDP	18,898	13,183	126.6	28.8%	$ 169,051	$ 743
PDNP	571	205	3.6	0.8%	4,340	393
PUD	7,008	4,257	46.3	10.6%	87,680	18,774
Total Proved:	26,477	17,645	176.5	40.2%	$ 261,071	$ 19,910
Michigan:						
PDP	469	76,263	79.1	18.0%	$ 133,618	$ 0
PDNP	140	6,914	7.8	1.8%	23,854	1,713
PUD	536	24,017	27.2	6.2%	56,935	14,755
Total Proved:	1,145	107,194	114.1	26.0%	$ 214,407	$ 16,468
Mid-Continent:						
PDP	1,438	15,900	24.5	5.6%	$ 41,271	$ 0
PDNP	53	863	1.2	0.3%	1,129	229

Total Proved:	1,491	16,763	25.7	5.9%	$ 42,400	$ 229
Total Corporate:						
PDP	25,105	157,668	308.3	70.2%	$ 516,287	$ 3,527
PDNP	1,051	14,214	20.6	4.7%	49,788	3,476
PUD	8,483	59,130	109.9	25.1%	218,548	59,323
Total Proved:	34,639	231,012	438.8	100%	$ 784,623	$ 66,326

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Summary of Oil and Natural Gas Properties and Projects

Gulf Coast/Permian Basin Region

Our Gulf Coast/Permian Basin operations include assets in Texas, Louisiana, Alabama and New Mexico. The Gulf Coast/Permian Basin region contributes 122.5 Bcfe (73% natural gas) of net proved reserves to our portfolio of operations, which represents 27.9% of our total net proved reserves. Approximately 90.9% of the proved reserves of our Gulf Coast/Permian Basin operations are related to properties in Texas.

Stuart City Reef Trend. We have leasehold interests in five fields located along a regional geologic structure known as the Stuart City Reef Trend in south - central Texas, where we are employing horizontal drilling technologies to develop gas reserves in the Edwards Limestone at 14,000 feet. We are also adding new oil and gas reserves from multiple zones within the Wilcox formation at approximately 10,000 feet. As of December 31, 2003, our Stuart City properties contained 35.5 Bcfe of net proved reserves primarily within the Word North field, the Yoakum field and the Kawitt field. Since June 30, 2004, we have completed two successful Edwards wells in our Stuart City Reef Trend properties, which are producing at a combined rate of 5.9 MMcf per day. We have also completed three new Wilcox wells, which are producing at a combined rate of 3.9 MMcf per day. Since June 30, 2004, production volumes in our Stuart City fields have increased by 62% to 14.6 MMcf per day.

Vicksburg Trend. We own interests in several fields within the Vicksburg Trend located in the vicinity of Nueces Bay in San Patricio and Nueces Counties, Texas. These fields include the Agua Dulce, Triple A, South Midway, and East White Point fields. Natural gas and oil production in this area is from multiple, low permeability sandstone reservoirs within the Vicksburg and Frio Formations at depths ranging between 4,000 and 15,000 feet.

In the Agua Dulce field, we have drilled one well during 2004, the Matthews #1, which proved up production in a new separate fault block. This well averaged 1.2 MMcf/d with 80 bopd (gross) for the last week of September 2004. We are currently drilling the second well in Agua Dulce. We have entered into a multi-well program in the South Midway field where Whiting holds a non-operated interest. During the third quarter of 2004, two wells have been drilled. Each of these wells has encountered multiple gas pay zones and are currently being completed.

Rocky Mountain Region

Our Rocky Mountain operations include assets in North Dakota, Montana, Colorado and Wyoming. As of January 1, 2004, our proved reserves in the Rocky Mountain region were 29.4 MMboe (90% oil), which accounted for 40.2% of our total proved reserves. The majority of our interests in the Rocky Mountain region are within North Dakota and Montana, where we have interests in 97 fields, 45 of which we operate. Approximately 87% of the proved reserves of our Rocky Mountain operations are related to assets in North Dakota.

Big Stick (Madison) Unit. The Big Stick field, which contains the Big Stick (Madison) Unit, is located in Billings County, North Dakota and produces from a series of stacked, oil saturated, porous dolomites within the Mission Canyon Formation at an average depth of 9,400 feet. We operate this unit and own a 62% working interest. Our net recoverable reserves at Big Stick at year end were 12.6 MMboe. Since acquiring this property, we have increased unit oil production by 38% through a combination of new drilling and enhancements to the artificial lift system. Current daily production net to our interest is 1,052 bopd. During the past year, we have been engaged in a detailed reservoir modeling study to determine the benefits and feasibility of implementing a waterflood within the unit. We are also developing our deeper, non-unitized interests at

Big Stick, and recently drilled a new well which identified gas pay in the Red River Formation at 12,700 feet and oil pay in the Duperow Formation at 11,000 feet.

Nisku A Drilling Program. We have a new exploration program and acreage position in western Billings County, North Dakota. The MOI Stillwater 21-23H discovery well was a previously existing wellbore that was deepened and drilled 1,848 feet horizontally within the Nisku Formation. The initial producing rate averaged 397 barrels of oil and 256 Mcf/d on a 25/64th-inch choke with 200 psi flowing tubing pressure. We drilled three subsequent wells during the third quarter of 2004. Two of these wells have produced results exceeding those of the Stillwater well. We are currently employing two drilling rigs and plan to drill five additional wells during the fourth quarter of 2004. We have an average 93.7% working interest and 92.8% net revenue interest in this program. In addition, we have operated and non-operated interests in four new Nisku wells in Golden Valley County, North Dakota and two locations which are planned for the fourth quarter of 2004. Production from the new wells in this area is comparable to that in our Billings County wells. Our average working interest in these wells is 47.6%, with a 39.1% net revenue interest.

Michigan Region

Our Michigan operations include assets in Michigan and Ohio. Virtually all of the proved reserves and pre-tax PV10% value associated with our Michigan operations are from properties located in the State of Michigan. The Michigan region contributes 114.1 Bcfe (94% natural gas) of net proved reserves to our portfolio of operations, which represents 26% of our total net proved reserves.

The majority of our Michigan production is from a non-conventional natural gas reservoir in the northern Michigan basin known as the Antrim Shale. The remainder of our production is from a variety of conventional oil and natural gas reservoirs in the eastern and southern portions of the basin. We operate the majority of our non-Antrim production as well as the West Branch and Stoney Point natural gas plants, while the majority of our Antrim production is operated by local companies in close cooperation with our technical staff.

Antrim Production. Natural gas is produced from fractures within the Antrim Shale at depths from 1,200 to 2,200 feet. The productive fairway of the Antrim is widespread across northern Michigan, covering a 3,400 square mile region. We own interests in 57 multi-well Antrim Shale natural gas projects within this area. As of January 1, 2004, our net proved reserves from these projects were 79.6 Bcfe (100% natural gas).

Approximately 10 of our Antrim Shale projects have significant remaining development potential. These projects are concentrated in three areas. In Briley Township, we have proved undeveloped reserves of 5.9 Bcf. The Old Vandy Projects in Charlevoix and Otsego Counties have proved undeveloped reserves of 2.0 Bcf. An additional 4.9 Bcf of proved undeveloped reserves are present within eight additional townships which are less geographically concentrated. During 2003, we drilled 15 wells, and we expect to drill 20 wells during 2004.

Conventional (non-Antrim) Production. Our non-Antrim Shale production is from conventional reservoirs (primarily the Prairie du Chien, Trenton and Black River Formations) located in Central Michigan. Estimated net proved reserves from these properties total 34.5 Bcfe (80% natural gas). We have interests in 20 oil and natural gas fields in this region and operate 7 of them.

Our undeveloped potential resides in three fields, West Branch, Clayton and South Buckeye. All are structurally trapped hydrocarbon accumulations and to date recoveries range from 4% to 37% of the in place hydrocarbons. Our undeveloped proved reserve potential in these three fields is estimated at 14.4 Bcfe versus 60 Bcfe produced to date. We are planning on drilling two wells in Clayton Field and one Well in South Buckeye Field during the fourth quarter 2004 and first quarter of 2005.

Mid-Continent Region

Our Mid-Continent operations include assets in Oklahoma, Arkansas and Kansas. The Mid-Continent region contributes 25.7 Bcfe (65% natural gas) of net proved reserves to our portfolio of operations, which represents 5.9% of total net proved reserves. The majority of the proved value within our Mid-Continent operations is related to properties in Oklahoma. The Oklahoma production is scattered throughout the state, with the single largest concentration being in the company-operated Putnam Oswego Unit, located in Dewey and Custer Counties in West-Central Oklahoma.

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Our proved properties located in Arkansas are operated, and are primarily in two fields, the Magnolia Smackover Pool Unit and the Wesson Hogg Sand Unit. Both of these fields are mature pressure maintenance units.

Acreage

The following table summarizes gross and net developed and undeveloped acreage at December 31, 2003 by region (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
Gulf Coast/Permian Basin	159,603	58,813	8,514	7,518	168,117	66,331
Rocky Mountains	137,038	66,507	286,000	90,400	423,038	156,907
Michigan	179,141	59,000			179,141	59,000
Mid-Continent	40,740	21,438	91,284	90,395	132,024	111,833
Total	516,522	205,758	385,798	188,313	902,320	394,071

Production History

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

	Year Ended December 31,		
	2003	2002	2001
Oil production (MMbbls)	2.6	2.3	2.1
Natural gas production (Bcf)	21.6	21.4	19.8
Total production (Bcfe)	37.2	35.2	32.4
Daily production (MMcfe/d)	101.8	96.4	88.8
Average sales prices:			
Natural gas (per Mcf)(1)	$ 4.78	$ 3.21	$ 3.82
Oil (per Bbl)(1)	$ 27.50	$ 23.35	$ 23.85
Total (per Mcfe)(1)	$ 4.73	$ 3.48	$ 3.88
Costs and expenses (per Mcfe):			
Lease operating expenses	$ 1.16	$ 0.93	$ 0.92
Production taxes	$ 0.29	$ 0.21	$ 0.20
Depreciation, depletion and amortization expense	$ 1.11	$ 1.24	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.34	$ 0.34	$ 0.34

(1) Before consideration of hedging transactions.

Productive Wells

The following table presents our ownership at December 31, 2003 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	
	Gross	Net	Gross	Net	Gross	Net
Gulf Coast/Permian Basin	1,571	139.7	852	282.0	2,423	421.7
Rocky Mountains	863	254.7	115	17.9	978	272.6
Michigan	78	57.0	968	368.3	1,046	425.3
Mid-Continent	372	151.2	187	78.8	559	230.0
Total	2,884	602.6	2,122	747.0	5,006	1,349.6

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Drilling Activity

We are engaged in numerous drilling activities on properties presently owned and intend to drill or develop other properties acquired in the future. The following table sets forth 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.

	Gulf Coast/ Permian Basin			Mid-Continent			Rocky Mountains			Michigan		Total		
	2003	2002	2001	2003	2002	2001	2003	2002	2001	2003	2002	2003	2002	2001
Gross:														
Productive	22	10	22	2	3	3	25	7	31	15	4	64	24	56
Dry	3	6	6				5	3	2			8	9	8
Total	25	16	28	2	3	3	30	10	33	15	4	72	33	64
Net:														
Productive	10.6	4.2	10.5	0.1	0.2	1.0	7.4	2.7	8.1	2.8	1.0	20.9	8.1	19.6
Dry	.9	2.2	1.9				3.0	2.1	1.9			3.9	4.3	3.8
Total	11.5	6.4	12.4	0.1	0.2	1.0	10.4	4.8	10.0	2.8	1.0	24.8	12.4	23.4

Our drilling activity from exploratory wells, which are included in the above table, include one productive gross well (0.2 net) in 2001 in the Gulf Coast/Permian Basin region, one dry gross well (0.15 net) in 2002 in the Gulf Coast/ Permian Basin region, three dry gross wells (1.55 net) in 2003, two of which were located in the Rocky Mountain region and one in the Gulf Coast/Permian Basin region.

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. For fiscal year 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 interferes 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

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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

Historically, the transportation and sale for resale of natural gas in inter state commerce have been regulated pursuant to the Natural Gas Act of 1938, the Natural Gas Policy Act of 1978 and regulations issued under those Acts by the Federal Energy Regulatory Commission, or the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act. The Decontrol Act removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage service on an open access basis to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 revised the FERC s pricing policy by waiving price ceilings for short-term released capacity for a two-year experimental period, and effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting. Most pipelines tariff filings to implement the requirements of Order No. 637 have been accepted by the FERC and placed into effect. While most major aspects of Order No. 637 have been upheld on judicial review, certain issues such as capacity segmentation and right of first refusal are pending further consideration by the FERC. We cannot predict what action FERC will take on these matters in the future, or whether the FERC s actions will survive further judicial review.

The Outer Continental Shelf Lands Act, which the FERC implements as to transportation and pipeline issues, 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. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. 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.

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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 transportation rates for oil 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. On remand, 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.

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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, also referred to as 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 may result in injunctive relief for failure to comply. These laws and regulations may require the acquisition of a permit before drilling 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 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.

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We currently own or lease, and in the past have owned or leased, properties that for many years have been used for the exploration and production of oil and 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. 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, 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. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced water, sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater 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 furtherance of the Clean Water Act, 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, if necessary to ensure compliance, in February 2006 with the implementation of such amended plans in August 2006. 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.

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Employees

As of September 30, 2004, we had 135 full-time employees, including five senior level geoscientists and fourteen petroleum engineers. Our employees are not represented by any labor union. We consider our relations with our employees to be satisfactory, and have never experienced a work stoppage or strike.

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.

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MANAGEMENT

Executive Officers and Directors

The following table sets forth information regarding our executive officers and directors as of September 30, 2004:

Name	Age	Position
James J. Volker	57	Chairman, President and Chief Executive Officer and Director
D. Sherwin Artus	66	Senior Vice President
James R. Casperson	57	Chief Financial Officer
James T. Brown	52	Vice President, Operations
John R. Hazlett	64	Vice President, Acquisitions and Land
J. Douglas Lang	54	Vice President Reservoir Engineering/Acquisitions
Patricia J. Miller	66	Vice President of Human Resources and Corporate Secretary
Mark R. Williams	48	Vice President, Exploration and Development
Michael J. Stevens	39	Controller and Treasurer
Thomas L. Aller	55	Director
Graydon D. Hubbard	70	Director
J. B. Ladd	80	Director
Palmer L. Moe	60	Director
Kenneth R. Whiting	76	Director

Our executive officers are elected by, and serve at the discretion of, our board of directors. The following biographies describe the business experience of our executive officers and directors:

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 R. Casperson joined us in February 2000 as Vice President of Finance and Chief Financial Officer. From June 1985 to February 2000, he was founder and president of Casperson, Inc., a private consulting firm. Mr. Casperson has twenty-six years of financial and operational experience in the oil and natural gas industry. Mr. Casperson holds a Bachelor s Degree from Texas Tech University.

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.

John R. Hazlett joined us in January 1994 as Vice President of Land and Acquisitions. He has forty-one years of experience in the oil and natural gas industry as a land man and acquisitions team leader. Mr. Hazlett is a graduate of Ft. Hays State College in Hays, Kansas. Mr. Hazlett is a Certified Professional Landman.

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 an MBA from the University of Denver. He is a registered Professional Engineer and has served on the national Board of Directors of the Society of Petroleum Evaluation Engineers.

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. Mrs. Miller attended business school at Otero Junior College in LaJunta, Colorado and at Texas A & I in Kingsville, Texas.

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 natural 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.

Michael J. Stevens joined us in May 2001 as Controller, and became Treasurer in January 2002. 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.

Thomas L. Aller has been a director of Whiting Petroleum Corporation since 2003 and has served as a director of Whiting Oil and Gas Corporation since 1997. Mr. Aller has served as Senior Vice President Energy Delivery of Alliant Energy Corporation and President of Interstate Power and Light Company since January 2004. Prior to that, he served as President of Alliant Energy Investments, Inc. since April 1998 and interim Executive Vice President Energy Delivery of Alliant Energy Corporation since September 2003. From 1993 to 1998, he served as Vice President of IES Investments. He received his Bachelor s Degree in political science from Creighton University and his Master s Degree in municipal administration from the University of Iowa.

Graydon D. Hubbard has served as a director of Whiting Petroleum Corporation since September 2003. He is a retired certified public accountant and was a partner of Arthur Andersen LLP in its Denver office for more than five years prior to his retirement in November 1989. Since 1991, he has served as a director of Allied Motion Technologies Inc., a company engaged in the business of designing, manufacturing and selling motion control products. Mr. Hubbard is also an author. He received his Bachelor s Degree in accounting from the University of Colorado.

J.B. Ladd has been a director of Whiting Petroleum Corporation since 2003 and has served as a director of Whiting Oil and Gas Corporation since its inception in 1980. He is an independent oil and natural gas operator with offices in Los Angeles, California and Denver, Colorado. He has over 50 years of experience in the oil and natural gas industry working for Texaco and Consolidated Oil and Gas, Inc. and as an independent oil and natural gas operator. He founded Ladd Petroleum Corporation in 1968, which was merged into Utah International in 1973 and later merged into General Electric Company in 1976. Mr. Ladd received a degree in petroleum engineering from the University of Kansas.

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Palmer L. Moe has served as a director of Whiting Petroleum Corporation since October 2004. He is Managing Director of Kronkosky Charitable Foundation in San Antonio, Texas, a position he has held since 1997. Mr. Moe is a certified public accountant and was a partner of Arthur Anderson & Co. in its San Antonio, Houston and Denver offices from 1965 to 1983. From 1983 until 1992, he served as President and Chief Operating Officer and a director of Valero Energy Corporation. He received his Bachelor s Degree in accounting from the University of Denver and completed the Senior Executive Development Course at the Alfred P. Sloan School of Management at the Massachusetts Institute of Technology.

Kenneth R. Whiting has been a director of Whiting Petroleum Corporation since 2003 and has served as a director of Whiting Oil and Gas Corporation since its inception in 1980. He was President and Chief Executive Officer of Whiting Oil and Gas Corporation from its inception until 1993, when he was appointed Vice President of International Business for IES Diversified. From 1978 to late 1979 he served as President of Webb Resources, Inc. He has many years of experience in the oil and natural gas industry, including his position as Executive Vice President of Ladd Petroleum Corporation. He was a partner and associate with Holme Roberts & Owen, Attorneys at Law. Mr. Whiting received his Bachelor s Degree in business from the University of Colorado and his J.D. from the University of Denver.

Board of Directors

Our certificate of incorporation and by-laws divide our board of directors into three classes. The directors serve staggered terms of three years, with the members of one class being elected in any year, as follows: (i) Palmer L. Moe and Kenneth R. Whiting have been designated as Class II Directors and will serve until the 2005 annual meeting of stockholders, (ii) Graydon D. Hubbard and James J. Volker have been designated as Class III Directors and will serve until the 2006 annual meeting of stockholders, and (iii) J.B. Ladd and Thomas L. Aller have been designated as Class I Directors and will serve until the 2007 annual meeting of stockholders, and in each case until their respective successors are duly elected and qualified.

Board Committees

Our board of directors has standing Audit, Compensation and Nominating and Governance Committees. Our board of directors has adopted a formal written charter for each of these committees.

The Audit Committee s primary duties and responsibilities are to assist our board of directors in monitoring the integrity of our financial statements, the independent auditor s qualifications and independence, the performance of our internal audit function and independent auditors and our compliance with legal and regulatory requirements. The Audit Committee is directly responsible for the appointment, retention, compensation, evaluation and termination of our independent auditors and has the sole authority to approve all audit and permitted non-audit engagement fees and terms. The Audit Committee is presently comprised of Messrs. Hubbard (Chairperson), Ladd and Moe, each of whom is an independent director under New York Stock Exchange listing standards applicable to directors generally and each of whom is an independent director under New York Stock Exchange listing standards and Securities and Exchange Commission rules applicable to Audit Committee members. Our board of directors has determined that Mr. Hubbard qualifies as an audit committee financial expert, as defined by Securities and Exchange Commission rules.

The Compensation Committee discharges the responsibilities of our board of directors with respect to our compensation programs and compensation of our executives and directors. The Compensation Committee has overall responsibility for approving and evaluating the compensation of executive officers (including the chief executive officer) and directors and our executive officer and director compensation plans, policies and programs. The Compensation Committee is presently comprised of Messrs. Hubbard (Chairperson), Ladd and Whiting, each of whom is an independent director under New York Stock Exchange listing standards.

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The principal functions of the Nominating and Governance Committee are to identify individuals qualified to become directors and recommend to our board of directors nominees for all directorships, identify directors qualified to serve on board committees and recommend to t our board of directors members for each committee, develop and recommend to our board of directors a set of corporation governance guidelines and otherwise take a leadership role in shaping our corporate governance. The Nominating and Governance Committee is presently comprised of Messrs. Hubbard, Moe and Whiting (Chairperson), each of whom is an independent director under New York Stock Exchange listing standards.

Director Compensation

Directors who are our employees receive no compensation for service as members of either the board of directors or board committees. Directors who are not our employees are paid an annual retainer of $20,000, an annual grant of $30,000 in restricted stock vesting ratably over a three year period and a fee of $1,500 for each board of directors meeting attended. Members of the Audit Committee receive an additional cash annual retainer of $2,500 ($12,000 for the chairman) and a fee of $1,500 for each Audit Committee meeting attended. Members of other board committees receive an additional cash annual retainer of $1,000 ($5,000 for the chairman) and a fee of $1,000 for each such committee meeting attended. In addition, Mr. Whiting receives payments under our Production Participation Plan with respect to his vested plan interests relating to his employment with us from 1982 to 1993. Mr. Whiting was paid $26,679 under the Production Participation Plan for 2003. Mr. Aller has received no compensation for his service on our board of directors to date because he is an employee of Alliant Energy Corporation, our former parent company.

Executive Officer Compensation

The following table sets forth certain information concerning the compensation earned each of the last two fiscal years by our Chief Executive Officer and each of four other most highly compensated executive officers whose total cash compensation exceeded $100,000 in the fiscal year ended December 31, 2003. The persons named in the table are sometimes referred to in this prospectus as the named executive officers.

Summary Compensation Table

		Annual Compensation		
Name and Principal Position	**Year**	**Salary($)**	**Bonus($)[1]**	**All Other Compensation($)[2]**
James J. Volker				
	2003	168,713	262,792	659,044
President and Chief Executive Officer	2002	165,000	205,041	
D. Sherwin Artus				
	2003	102,250	183,211	680,044
Senior Vice President	2002	173,309	156,641	11,000
John R. Hazlett				
	2003	115,952	139,133	653,042
Vice President, Acquisitions and Land	2002	112,050	114,941	11,000
Mark R. Williams	2003	95,406	150,672	626,041
	2002	91,510	124,819	11,000

Vice President, Exploration and Development				
Patricia J. Miller				
	2003	99,579	138,930	427,988
Vice President, Human Resources and Corporate Secretary	2002	96,228	114,630	11,000

(1) Except for incentive bonuses to Mr. Volker of $54,788 for 2002 and $76,000 for 2003, all amounts presented under the Bonus column were paid under our Production Participation Plan, which is allocated a specific percentage of net income with respect to certain oil and natural gas wells.

(2) These amounts for 2003 consist of (i) matching contributions of $12,000 by us under our 401(k) Employee Savings Plan to each of the named executive officers other than Mr. Volker, who received no matching contribution, and Ms. Miller, who received a matching contribution of $11,960 and (ii) payments valued at

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$659,044 to Mr. Volker, $668,044 to Mr. Artus, $641,042 to Mr. Hazlett, $614,041 to Mr. Williams and $416,028 to Ms. Miller pursuant to our Phantom Equity Plan in connection with our initial public offering in November 2003. After withholding for taxes, these payments were made in the form of shares of our common stock resulting in the issuance of 25,052 shares to Mr. Volker, 25,394 shares to Mr. Artus, 24,368 shares to Mr. Hazlett, 23,341 shares to Mr. Williams and 15,814 shares to Ms. Miller. The Phantom Equity Plan terminated after the issuance of such shares.

Compensation Committee Interlocks and Insider Participation

During 2003, Graydon D. Hubbard, J.B. Ladd and Kenneth R. Whiting served on the Compensation Committee of our board of directors. Mr. Whiting was President and Chief Executive Officer of Whiting Oil and Gas Corporation from its inception in 1980 until 1993. None of our executive officers serve as a member of the board of directors or compensation committee of any entity that has one or more of its executive officers serving as a member of our board of directors or compensation committee.

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PRINCIPAL HOLDERS OF COMMON STOCK

Set forth below is information regarding the beneficial ownership of Whiting Petroleum Corporation common stock by Resources, each of our directors and executive officers, all directors and executive officers as a group and each other person known to us to beneficially own at least 5% of our outstanding common stock. Unless otherwise indicated, the address for each of the persons below is in care of our principal executive offices.

Beneficial ownership is determined under the rules of the Securities and Exchange Commission. In general, these rules attribute beneficial ownership of securities to persons who possess sole or shared voting power and/or investment power with respect to those securities and includes, among other things, securities that an individual has the right to acquire within 60 days. Unless otherwise indicated, the persons identified in the following tables have sole voting and investment power with respect to all shares shown as beneficially owned by them.

Alliant Energy Resources, Inc.

The following table sets forth certain information regarding the beneficial ownership by Resources and Alliant Energy of our common stock as of September 30, 2004 and as adjusted to give effect to the concurrent sale of 1,080,000 shares offered by Resources. This offering and the concurrent offering of 1,080,000 shares of our common stock by Resources are not contingent on one another. We will not receive any proceeds from the successful completion of the offering of our shares by Resources.

	Shares of Common Stock Beneficially Owned Prior to Concurrent Offering		Number of Shares Being Offered	Shares of Common Stock Beneficially Owned After Concurrent Offering	
Name	Number	Percent		Number	Percent
Alliant Energy Corporation[1] 4902 North Biltmore Lane Madison, WI 53718	1,080,000	5.1%	1,080,000		

[1] Alliant Energy is the beneficial owner of the shares of common stock owned by its wholly-owned subsidiary, Resources.

Management and Directors

The following table sets forth certain information regarding the beneficial ownership of our common stock as of October 26, 2004 by: (i) each of our directors; (ii) each of the executive officers named in the Summary Compensation Table set forth under Management Executive Compensation ; and (iii) all of our directors and executive officers (including the executive officers named in the Summary Compensation Table) as a group. Each of the holders listed below has sole voting and investment power over the shares beneficially owned.

Name of Beneficial Owner	Shares of Common Stock Beneficially Owned	Percent of Common Stock Beneficially Owned
James J. Volker	56,047	*
Thomas L. Aller	1,300	*
Graydon D. Hubbard	7,545	*
J. B. Ladd	61,545	*
Palmer L. Moe	1,000	*
Kenneth R. Whiting	1,545	*
D. Sherwin Artus	33,118	*
John R. Hazlett	32,092	*
Mark R. Williams	26,815	*
Patricia J. Miller	21,063	*
All directors and executive officers as a group (14 persons)	351,737	1.7%

* Denotes less than 1%.

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Other Beneficial Owners

The following table sets forth certain information regarding beneficial ownership by the only persons known to Whiting to own more than 5% of its outstanding common stock other than Alliant Energy and Resources. The beneficial ownership information set forth below is as reported in filings made by the beneficial owners with the Securities and Exchange Commission.

	Amount and Nature of Beneficial Ownership					
	Voting Power		Investment Power			Percent
Name and Address of Beneficial Owner	Sole	Shared	Sole	Shared	Aggregate	of Class
Wellington Management Company, LLP 75 State Street Boston, MA 02109		1,479,850		1,760,230	1,760,230	9.4%
T. Rowe Price Associates, Inc. (1) 100 E. Pratt Street Baltimore, MD 21202	184,400		979,800		979,800	5.2%
Third Avenue Management LLC 622 Third Avenue, 32nd Floor New York, NY 10017	949,950		949,950		949,950	5.0%

(1) These securities are owned by various individual and institutional investors for which T. Rowe Price Associates, Inc. serves as investment adviser with power to direct investments and/or sole power to vote the securities. For purposes of the reporting requirements of the Securities Exchange Act of 1934, T. Rowe Price Associates, Inc. is deemed to be the beneficial owner of such securities; however, T. Rowe Price Associates, Inc. has expressly disclaimed beneficial ownership of such securities.

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RELATIONSHIP WITH ALLIANT ENERGY CORPORATION

Prior to our initial public offering in November 2003, we were a wholly-owned subsidiary of Resources, which is a wholly-owned subsidiary of Alliant Energy. In connection with our initial public offering, we entered into a series of agreements with Alliant Energy, including a master separation agreement, a tax separation and indemnification agreement and a registration rights agreement. We have set forth below a summary description of the material terms of each of those agreements.

Master Separation Agreement

In connection with our initial public offering, Whiting Petroleum Corporation, Whiting Oil and Gas Corporation, Alliant Energy and Resources entered into a master separation agreement. The master separation agreement contains provisions governing certain aspects of the relationship between us and Alliant Energy following the completion of the initial public offering, as summarized below.

Pursuant to the master separation agreement, immediately prior to the completion of our initial public offering, Resources transferred all of the outstanding stock of Whiting Oil and Gas Corporation to Whiting Petroleum Corporation in exchange for 18,330,000 shares of common stock of Whiting Petroleum Corporation, which constituted all of its outstanding common stock at such time, and a promissory note in the aggregate principal amount of $3.0 million. The promissory note bears interest at a fixed rate equal to 5.0% per year and the entire unpaid balance, together with interest, will be due and payable November 25, 2005.

The master separation agreement provides that we were responsible for withholding from payments to participants under our phantom equity plan all amounts required by law. Alliant Energy made a capital contribution to Whiting Oil and Gas Corporation equal to the aggregate amount of the tax withholding payments paid to the Internal Revenue Service or other appropriate governmental agency pursuant to the tax separation and indemnification agreement.

Alliant Energy agreed to indemnify us for any liabilities related to our initial public offering the substance of which is based solely on the information provided by Alliant Energy about Alliant Energy contained in certain sections of the prospectus relating to our initial public offering and for any liability resulting from the breach of any representation or covenant by Alliant Energy set forth in the master separation agreement, the registration rights agreement or the tax separation and indemnification agreement. We agreed to indemnify Alliant Energy for any other liabilities related to the registration statement relating to our initial public offering, and for all past, present and future liabilities associated with our business and operations (other than certain liabilities specified in the master separation agreement) and for any liability resulting from the breach of any representation or covenant by us set forth in the master separation agreement, the registration rights agreement or the tax separation and indemnification agreement.

Tax Separation and Indemnification Agreement

Prior to our initial public offering, Whiting Oil and Gas Corporation and its subsidiaries were members of the Alliant Energy consolidated tax group and were included in the consolidated federal income tax return filed by Alliant Energy, as well as various consolidated or combined state, local and foreign tax returns filed by Alliant Energy. As a result of the share exchange and the completion of our initial public offering, Whiting Oil and Gas Corporation and its subsidiaries ceased to be members of the Alliant Energy consolidated tax group and became members of our consolidated tax group and are included in the consolidated federal and certain other consolidated or combined state, local and foreign income tax returns filed by us.

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 basis of our assets. This additional basis is 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 basis 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 basis 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.

Registration Rights Agreement

In connection with our initial public offering, Whiting Petroleum Corporation, Alliant Energy and Resources entered into a registration rights agreement. The registration rights agreement provides that, at any time until November 25, 2006, Alliant Energy has the right to demand three registrations of its shares of our common stock. We have agreed to use our best efforts to file a registration statement with the SEC within 45 days of receipt of a request to do so and to use our best efforts to cause such registrations statement to become effective as soon as possible. If our board of directors determines in good faith that a registration statement would cause us to disclose material nonpublic information that would be materially detrimental to us or that would materially interfere with any material financing, acquisition, corporate reorganization or merger or other transaction involving us, then we may postpone filing a registration statement for up to 45 days once in a twelve month period. The registration rights agreement also provides that, until November 25, 2006, Alliant Energy will have the right to participate in any registration of shares of common stock by us, subject to customary limitations. All expenses payable in connection with such registrations will be paid by us, except that Alliant Energy will pay all underwriting discounts and commissions applicable to the sale of its shares of our common stock and the fees and expenses of its separate advisors and legal counsel.

The registration statement of which this prospectus is a part is intended to satisfy our obligations under the registration rights agreement. If Alliant Energy and Resources sell all of the 1,080,000 shares of our common stock registered for sale by them pursuant to such registration statement, then they will no longer own any shares of our common stock.

Other Relationships and Transactions

In 1994, we acquired a 6% working interest in the Point Arguello complex, consisting of working interests in the Point Arguello Unit located in federal waters offshore Santa Barbara County, California. Our wholly-owned subsidiary, Whiting Programs, Inc., became a partner in certain partnerships which owned onshore facilities that served the offshore unit. Resources has guaranteed the obligations of Whiting Programs, Inc. under the partnership agreements governing those partnerships.

We had borrowed a total of $80.5 million from Alliant Energy under a note that bore interest at 6.9% during 2003. We incurred approximately $1.2 million in interest expense related to this note during the year ended December 31, 2003. On March 31, 2003, Alliant Energy converted the outstanding balance of this note into our equity.

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DESCRIPTION OF CAPITAL STOCK

The authorized capital stock of Whiting Petroleum Corporation consists of 75,000,000 shares of common stock, $0.001 par value per share and 5,000,000 shares of preferred stock, $0.001 par value per share.

The following summary of the capital stock and certificate of incorporation and by-laws of Whiting Petroleum Corporation does not purport to be complete and is qualified in its entirety by reference to the provisions of applicable law and to our certificate of incorporation and by-laws.

Common Stock

There were 21,100,347 shares of our common stock outstanding as of September 30, 2004. Holders of our common stock are entitled to one vote for each share held on all matters submitted to a vote of stockholders and do not have cumulative voting rights. Accordingly, holders of a majority of the shares of our common stock entitled to vote in any election of directors may elect all of the directors standing for election. Holders of our common stock are entitled to receive proportionately any dividends if and when such dividends are declared by our board of directors, subject to any preferential dividend rights of outstanding preferred stock. Upon the liquidation, dissolution or winding up of our company, the holders of our common stock are entitled to receive ratably our net assets available after the payment of all debts and other liabilities and subject to the prior rights of any outstanding preferred stock. Holders of our common stock have no preemptive, subscription, redemption or conversion rights. The rights, preferences and privileges of holders of our common stock are subject to, and may be adversely affected by, the rights of the holders of shares of any series of preferred stock that we may designate and issue in the future.

Preferred Stock

Under the terms of our certificate of incorporation, our board of directors is authorized to designate and issue shares of preferred stock in one or more series without stockholder approval. Our board of directors has discretion to determine the rights, preferences, privileges and restrictions, including voting rights, dividend rights, conversion rights, redemption privileges and liquidation preferences, of each series of preferred stock. It is not possible to state the actual effect of the issuance of any shares of preferred stock upon the rights of holders of our common stock until the board of directors determines the specific rights of the holders of the preferred stock. However, these effects might include:

- restricting dividends on the common stock;
- diluting the voting power of the common stock;
- impairing the liquidation rights of the common stock; and
- delaying or preventing a change in control of our company.

We have no present plans to issue any shares of preferred stock.

Delaware Anti-Takeover Law and Charter and By-law Provisions

We are subject to the provisions of Section 203 of the Delaware General Corporation Law. In general, the statute prohibits a publicly held Delaware corporation from engaging in a business combination with an interested stockholder for a period of three years after the date of the transaction in which the person became an interested stockholder, unless the business combination or the transaction by which the person became an interested stockholder is approved by the corporation s board of directors and/or stockholders in a prescribed manner or the person owns at least 85% of the corporation s outstanding voting stock after giving effect to the transaction in which the person became an interested stockholder. The term business combination includes mergers, asset sales and other transactions resulting in a financial benefit to the interested stockholder. Subject to certain exceptions, an interested stockholder is a person who, together with affiliates and associates, owns, or within three years did own, 15% or more of the corporation s voting stock. A Delaware corporation may opt out from the application of Section 203 through a provision in its certificate of incorporation or by-laws. We have not opted out from the application of Section 203.

Under our certificate of incorporation and by-laws, our board of directors is divided into three classes, with staggered terms of three years each. Each year the term of one class expires. Any vacancies on the board of directors may be filled only by a majority vote of the remaining directors. Our certificate of incorporation and by-laws also provide that any director may be removed from office, but only for cause and only by the affirmative vote of the holders of at least 70% of the voting power of our then outstanding capital stock entitled to vote generally in the election of directors.

Our certificate of incorporation prohibits stockholders from taking action by written consent without a meeting and provides that meetings of stockholders may be called only by our chairman of the board, our president or a majority of our board of directors. Our by-laws further provide that nominations for the election of directors and advance notice of other action to be taken at meetings of stockholders must be given in the manner provided in our by-laws, which contain detailed notice requirements relating to nominations and other action.

The foregoing provisions of our certificate of incorporation and by-laws and the provisions of Section 203 of the Delaware General Corporation Law could have the effect of delaying, deferring or preventing a change of control of our company.

Liability and Indemnification of Officers and Directors

Our certificate of incorporation provides that our directors will not be personally liable to us or our stockholders for monetary damages for breach of fiduciary duty as a director, except for liability (1) for any breach of a director s duty of loyalty to us or our stockholders, (2) for acts or omissions not in good faith or which involve intentional misconduct or a knowing violation of law, (3) under Section 174 of the Delaware General Corporation Law, or (4) for any transaction from which the director derives an improper personal benefit. Moreover, the provisions do not apply to claims against a director for violations of certain laws, including federal securities laws. If the Delaware General Corporation Law is amended to authorize the further elimination or limitation of directors liability, then the liability of our directors will automatically be limited to the fullest extent provided by law. Our certificate of incorporation and by-laws also contain provisions to indemnify our directors and officers to the fullest extent permitted by the Delaware General Corporation Law. In addition, we may enter into indemnification agreements with our directors and officers. These provisions and agreements may have the practical effect in certain cases of eliminating the ability of stockholders to collect monetary damages from our directors and officers. We believe that these contractual agreements and the provisions in our certificate of incorporation and by-laws are necessary to attract and retain qualified persons as directors and officers.

Transfer Agent and Registrar

The transfer agent and registrar for our common stock is Computershare Trust Company, Inc.

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UNDERWRITING

We intend to offer the shares through the underwriters. Merrill Lynch, Pierce, Fenner & Smith Incorporated is acting as the representative of the underwriters named below. Subject to the terms and conditions described in a purchase agreement among us and the underwriters, we have agreed to sell to the underwriters, and the underwriters severally have agreed to purchase from us, the number of shares listed opposite their names below.

Underwriter	Number of Shares
Merrill Lynch, Pierce, Fenner & Smith Incorporated	
A.G. Edwards & Sons, Inc.	
Banc of America Securities LLC	
J. P. Morgan Securities Inc.	
Raymond James & Associates, Inc.	
Petrie Parkman & Co., Inc.	
KeyBanc Capital Markets, a Division of McDonald Investments Inc.	
Simmons & Company International	
Total	

The underwriters have agreed to purchase all of the shares sold under the purchase agreement if any of these shares are purchased. If an underwriter defaults, the purchase agreement provides that the purchase commitments of the nondefaulting underwriters may be increased or the purchase agreement may be terminated.

We have agreed to indemnify the underwriters against certain liabilities, including liabilities under the Securities Act, or to contribute to payments the underwriters may be required to make in respect of those liabilities. These obligations are in addition to the contractual obligations between Alliant Energy and us. See Relationship with Alliant Energy Corporation Registration Rights Agreement.

The underwriters are offering the shares, subject to prior sale, when, as and if issued to and accepted by them, subject to approval of legal matters by their counsel, including the validity of the shares, and other conditions contained in the purchase agreement, such as the receipt by the underwriters of officer s certificates and legal opinions. The underwriters reserve the right to withdraw, cancel or modify offers to the public and to reject orders in whole or part.

Commissions and Discounts

The representatives have advised us that the underwriters propose initially to offer the shares to the public at the public offering price on the cover page of this prospectus and to dealers at that price less a concession not in excess of $ per share. The underwriters may allow, and the dealers may reallow, a discount not in excess of $ per share to other dealers. After the public offering, the public offering price, concession and discount may be changed.

The following table shows the public offering price, underwriting discount and proceeds to us before expenses. The information assumes either no exercise or full exercise by the underwriters of the overallotment option.

	Per Share	Without Option	With Option
Public offering price	$	$	$
Underwriting discount	$	$	$
Proceeds, before expenses, to us	$	$	$

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The expenses of the offering and the concurrent offering by Resources, not including the underwriting discounts, are estimated at $575,000 and are payable by us, except that Merrill Lynch has agreed to reimburse us for certain printing costs and legal and accounting fees and expenses relating to the concurrent offering by Resources.

Overallotment Option

We have granted an option to the underwriters to purchase up to 1,125,000 additional shares at the public offering price less the underwriting discount. The underwriters may exercise this option for 30 days from the date of this prospectus solely to cover any overallotments. If the underwriters exercise this option, each will be obligated, subject to conditions contained in the purchase agreement, to purchase a number of additional shares proportionate to that underwriter s initial amount reflected in the above table.

No Sale of Similar Securities

We, Resources, our executive officers and our directors have agreed, with exceptions, not to sell or transfer any of our common stock for 90 days after the date of this prospectus without first obtaining the written consent of Merrill Lynch on behalf of the underwriters. Specifically, we and these other individuals have agreed not to directly or indirectly

- offer, pledge, sell or contract to sell any common stock,
- sell any option or contract to purchase any common stock,
- purchase any option or contract to sell any common stock,
- grant any option, right or warrant for the sale of any common stock,
- lend or otherwise dispose of or transfer any common stock, or
- enter into any swap or other agreement that transfers, in whole or in part, the economic consequence of ownership of any common stock whether any such swap or transaction is to be settled by delivery of shares or other securities, in cash or otherwise.

This lock-up provision applies to common stock and to securities convertible into or exchangeable or exercisable for or repayable with common stock. It also applies to common stock owned now or acquired later by the person executing the agreement or for which the person executing the agreement later acquires power of disposition.

New York Stock Exchange Listing

The shares are listed on the New York Stock Exchange under the symbol WLL.

Price Stabilization, Short Positions and Penalty Bids

Until the distribution of the shares is completed, SEC rules may limit underwriters and selling group members from bidding for and purchasing our common stock. However, the representative may engage in transactions that stabilize the price of the common stock, such as bids or purchases to peg, fix or maintain that price.

If the underwriters create a short position in the common stock in connection with the offering, i.e., if they sell more shares than are listed on the cover of this prospectus, the representative may reduce that short position by purchasing shares in the open market. The representative may also elect to reduce any short position by exercising all or part of the overallotment option described above. Purchases of our common stock to stabilize its price or to reduce a short position may cause the price of our common stock to be higher than it might be in the absence of such purchases.

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Neither we nor any of the underwriters makes any representation or prediction as to the direction or magnitude of any effect that the transactions described above may have on the price of the common stock. In addition, neither we nor any of the underwriters makes any representation that the representative will engage in these transactions or that these transactions, once commenced, will not be discontinued without notice.

Electronic Distribution

Merrill Lynch will be facilitating Internet distribution for this offering to certain of its Internet subscription customers. Merrill Lynch intends to allocate a limited number of shares for sale to its online brokerage customers. An electronic prospectus is available on the Internet Website maintained by Merrill Lynch. Other than the prospectus in electronic format, the information on the Merrill Lynch Website is not part of this prospectus.

Other Relationships

Some of the underwriters and their affiliates have engaged in, and may in the future engage in, investment banking and other commercial dealings in the ordinary course of business with us. In addition, affiliates of J. P. Morgan Securities Inc., Banc of America Securities LLC and KeyBanc Capital Markets, a Division of McDonald Investments Inc. are lenders under Whiting Oil and Gas Corporation s bank credit facility and each will receive its proportionate share of the net proceeds of the offering used to repay a portion of the outstanding balance under the credit facility. Because more than ten percent of the net proceeds may be paid to affiliates of members of the National Association of Securities Dealers, Inc. participating in the offering, the offering will be conducted in accordance with NASD Conduct Rule 2710(c)(8).

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LEGAL MATTERS

The validity of the shares of common stock to be sold in the offering will be passed upon for us by the law firm of Foley & Lardner LLP. Welborn Sullivan Meck & Tooley, P.C. will pass on certain legal matters relating to us and our subsidiaries for us in connection with this offering. Certain legal matters will be passed upon for the underwriters by the law firm of Vinson & Elkins L.L.P.

EXPERTS

The consolidated financial statements of Whiting Petroleum Corporation as of December 31, 2003 and 2002 and for each of the three years in the period ended December 31, 2003, included in this prospectus have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein (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 effective January 1, 2003) and have been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

The statements of revenues and direct operating expenses of the Permian Basin Acquisition Properties for the years ended December 31, 2003, 2002 and 2001, included in this prospectus have been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as stated in their report appearing herein and have been so included in reliance upon the report of such firm given upon their authority as experts in accounting and auditing.

Certain information with respect to our oil and natural gas reserves derived from the reports of Cawley Gillespie & Associates, Inc., R.A. Lenser & Associates, Inc. and Ryder Scott Company, L.P., each independent petroleum engineering consultants, has been included in this prospectus on the authority of said firms as experts in petroleum engineering.

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WHERE YOU CAN FIND MORE INFORMATION

We file annual, quarterly and current reports, proxy statements and other information with the Securities and Exchange Commission. We have also filed with the SEC under the Securities Act a registration statement on Form S-1 with respect to the common stock offered by this prospectus. This prospectus, which constitutes part of the registration statement, does not contain all the information set forth in the registration statement or the exhibits and schedules which are part of the registration statement, portions of which are omitted as permitted by the rules and regulations of the SEC. Statements made in this prospectus regarding the contents of any contract or other document are summaries of the material terms of the contract or document. With respect to each contract or document filed as an exhibit to the registration statement, reference is made to the corresponding exhibit. For further information pertaining to us and the common stock offered by this prospectus, reference is made to the registration statement, including the exhibits and schedules thereto, copies of which may be inspected without charge at the public reference facilities of the SEC at 450 Fifth Street, N.W., Washington, D.C. 20549. Copies of all or any portion of the registration statement may be obtained from the SEC at prescribed rates. Information on the public reference facilities may be obtained by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a web site that contains reports, proxy and information statements and other information that is filed through the SEC s EDGAR System. The web site can be accessed at *http://www.sec.gov*.

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors of

Whiting Petroleum Corporation:

We have audited the accompanying consolidated balance sheets of Whiting Petroleum Corporation and Subsidiaries (the Company) as of December 31, 2003 and 2002, and the related consolidated statements of income, stockholder s equity and comprehensive income, and cash flows for each of the three years in the period ended December 31, 2003. These financial statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these financial statements 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 the Company as of December 31, 2003 and 2002, and the results of its operations and its cash flows for each of the three years in the period ended December 31, 2003 in conformity with accounting principles generally accepted in the United States of America.

As discussed in Note 1 to the 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.

/s/ DELOITTE & TOUCHE LLP

February 25, 2004

Denver, Colorado

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF DECEMBER 31, 2003 AND 2002

(In thousands, except per share data)

	2003	2002
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 53,585	$ 4,833
Accounts receivable trade	24,020	22,509
Income taxes and other receivables		8,162
Prepaid expenses and other	2,666	3,542
Total current assets	80,271	39,046
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	615,764	553,902
Unproved properties	1,637	1,593
Other property and equipment	2,684	3,454
Total property and equipment	620,085	558,949
Less accumulated depreciation, depletion and amortization	(192,794)	(154,352)
Property and equipment net	427,291	404,597
OTHER LONG-TERM ASSETS	9,988	4,825
DEFERRED INCOME TAX ASSET	18,735	
TOTAL	$ 536,285	$ 448,468

(Continued)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF DECEMBER 31, 2003 AND 2002

(In thousands, except per share data)

	2003	2002
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 15,918	$ 8,474
Oil and gas sales payable	2,406	903
Accrued employee benefits	5,275	4,259
Production taxes payable	2,574	2,137
Derivative liability	2,145	3,300
Income taxes and other liabilities	693	585
Total current liabilities	29,011	19,658
DEFERRED INCOME TAX LIABILITY		28,235
ABANDONMENT LIABILITY	23,021	4,232
PRODUCTION PARTICIPATION PLAN LIABILITY	7,868	8,053
TAX SHARING LIABILITY	28,790	
LONG-TERM DEBT	188,017	265,472
COMMITMENTS AND CONTINGENCIES (Note 7)		
STOCKHOLDERS EQUITY:		
Common stock, $.001 par value; 18,750,000 authorized, issued and outstanding	19	19
Additional paid-in capital	170,367	53,219
Accumulated other comprehensive loss	(223)	(1,550)
Retained earnings	89,415	71,130
Total stockholders equity	259,578	122,818
TOTAL	$ 536,285	$ 448,468

See notes to consolidated financial statements.

(Concluded)

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF INCOME

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

	2003	2002	2001
REVENUES:			
Oil and gas sales	$ 175,731	$ 122,709	$ 125,286
Gain (loss) on oil and gas hedging activities	(8,680)	(3,184)	2,266
Gain on sale of oil and gas properties		978	11,698
Interest income and other	330	9	205
Total	167,381	120,512	139,455
COSTS AND EXPENSES:			
Lease operating	43,213	32,867	29,767
Production taxes	10,691	7,363	6,482
Depreciation, depletion and amortization	41,256	43,601	26,904
Exploration	3,186	1,811	793
General and administrative	12,805	11,980	10,939
Phantom equity plan	10,914		
Interest expense	9,177	10,938	10,233
Total costs and expenses	131,242	108,560	85,118
INCOME BEFORE INCOME TAXES	36,139	11,952	54,337
INCOME TAX EXPENSE (BENEFIT):			
Current	2,389	(6,408)	1,815
Deferred	11,560	10,631	11,279
Total income tax expense	13,949	4,223	13,094
INCOME FROM CONTINUING OPERATIONS	22,190	7,729	41,243
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	(3,905)		
NET INCOME	$ 18,285	$ 7,729	$ 41,243
Basic and diluted earnings per share from continuing operations	$ 1.18	$ 0.41	$ 2.20
Cumulative change in accounting principle	(0.20)		
BASIC AND DILUTED NET INCOME PER COMMON SHARE	$ 0.98	$ 0.41	$ 2.20
WEIGHTED AVERAGE SHARES OUTSTANDING	18,750	18,750	18,750

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

	Common Stock						
	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Total Stockholders Equity	Comprehensive Income
BALANCES January 1, 2001	18,750	$ 19	$ 47,856	$ 22,158	$ 15	$ 70,048	
Net income				41,243		41,243	41,243
Unrealized net gain on marketable equity securities for sale					88	88	88
Reclass to earnings					87	87	87
BALANCES December 31, 2001	18,750	19	47,856	63,401	190	111,466	41,418
Net income				7,729		7,729	7,729
Unrealized net gain on marketable equity securities for sale					240	240	240
Tax contribution from Alliant			5,363			5,363	
Change in derivative instrument fair value					(1,980)	(1,980)	(1,980)
BALANCES December 31, 2002	18,750	19	53,219	71,130	(1,550)	122,818	5,989
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	$ 89,415	$ (223)	$ 259,578	$ 19,612

See notes to consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 AND 2001

(In thousands, except per share data)

	2003	2002	2001
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 18,285	$ 7,729	$ 41,243
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of oil and gas properties		(978)	(11,700)
Depreciation, depletion and amortization	41,256	43,601	35,902
Deferred income taxes	11,560	10,631	11,288
Amortization of bank fees	1,091	71	
Accretion of tax sharing agreement	220		
Phantom equity plan	6,510		
Cumulative change in accounting principle	3,905		
Changes in assets and liabilities:			
Accounts receivable	(307)	(1,129)	2,165
Income taxes and other receivable	3,814	1,538	(5,670)
Other assets	295	(1,229)	315
Abandonment liability	(147)	(48)	(8,997)
Production participation plan	651	1,685	1,473
Current liabilities	9,229	710	(3,672)
Net cash provided by operating activities	96,362	62,581	62,347
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(47,555)	(165,443)	(99,621)
Acquisition of partnership interests, net of cash received	(4,453)		
Proceeds from sale of properties		1,534	19,570
Restricted cash		6,434	(6,434)
Net cash used in investing activities	(52,008)	(157,475)	(86,485)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Other advances (repayments) from Alliant, net	4,616	(83,119)	23,869
Proceeds from bank loan		185,000	
Debt issuance costs	(218)	(3,171)	
Net cash provided by financing activities	4,398	98,710	23,869
NET CHANGE IN CASH AND CASH EQUIVALENTS	48,752	3,816	(269)
CASH AND CASH EQUIVALENTS:			
Beginning of period	4,833	1,017	1,286
End of period	$ 53,585	$ 4,833	$ 1,017

SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid (refunded) for income taxes Alliant	$ (1,425)	$ (7,946)	$ 8,586
Cash paid for interest	$ 6,464	$ 10,866	$ 10,233
NONCASH FINANCING ACTIVITIES:			
Alliant debt converted to equity	80,931		

See notes to consolidated financial statements.

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NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations Whiting Petroleum Corporation (Whiting or the Company) 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 our common stock by Alliant Energy, the Company in effect split its common stock, issuing 18,330 shares for the 1 previously held by Alliant Energy. All periods presented have been adjusted to reflect the current capital structure. Alliant Energy historically provided the Company with cash management and other services. Whiting acquires, develops and explores for producing oil and gas properties primarily in the Gulf Coast/Permian Basin, Rocky Mountains, Michigan, and Mid-Continent regions of the United States.

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 is the sole general partner. All significant intercompany balances and transactions have been eliminated in consolidation.

Use of Estimates The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires management to make significant estimates. These estimates are an integral part of the financial statements and actual results could differ from those estimates. Certain estimates associated with the carrying amount of oil and gas properties are particularly sensitive to changes in pricing, production rates and cost. A decline in the price of oil or gas or rate of production or increase in costs associated with the operations of oil and gas properties could adversely impact the economic value of the oil and gas properties.

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

Fair Value of Financial Instruments The Company s financial instruments, including cash and cash equivalents, restricted cash, accounts receivable and payable are carried at cost, which approximates their fair value because of the short-term maturity of these instruments. The related party debt and bank loan have a recorded value that approximates its fair value as both instruments have variable interest rates tied to current market rates. The Company s derivative instruments and investment in available for sale securities are marked-to-market with changes in value being recorded in accumulated other comprehensive income.

Concentration of Credit Risk Substantially all of the Company s receivables are within the oil and gas industry, primarily from the sale of oil and gas products and billings to working interest owners. Although diversified within many companies, collectibility is dependent upon the general economic conditions of the industry. Most of the receivables are not collateralized and to date, the Company has had minimal bad debts.

Further, our natural gas futures and swap contracts also expose us to credit risk in the event of nonperformance by counterparties. Generally, these contracts are with major investment grade financial institutions and historically the Company have not experienced material credit losses. The Company believes that our credit risk related to the natural gas futures and swap contracts is no greater than the risk associated with primary contracts and that the elimination of price risk reduces volatility in our reported results of operations, financial position and cash flows from period to period and lowers our overall business risk; but, as a result of Whiting s hedging activities the Company may be exposed to greater credit risk in the future. No single purchaser of oil and gas accounted for 10% or more of total sales for the years ended December 31, 2003, 2002 or 2001.

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At December 31, 2003 and 2002, the Company had recorded an allowance for doubtful accounts of $300 and $250 and, respectively.

Oil and Gas Producing Activities The Company follows the successful efforts method of accounting for its oil and gas properties. Under this method of accounting, all property acquisition costs and costs of exploratory and development wells are capitalized when incurred, 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. The costs of development wells are capitalized whether productive or nonproductive.

Interest cost is capitalized as a component of property cost for exploration and development projects that require a period of time to be readied for their intended use. During 2003, 2002 and 2001, capitalized interest was insignificant.

Geological and geophysical costs of exploratory prospects and the costs of carrying and retaining unproved properties are expensed as incurred. An impairment is recorded for unproved properties if the capitalized costs are not considered to be realizable. Depletion, depreciation and amortization (DD&A) of capitalized costs of proved oil and gas properties is provided on a field-by-field basis using the units of production method based upon proved reserves. The computation of DD&A takes into consideration the anticipated proceeds from equipment salvage and the Company s expected cost to abandon its well interests.

The Company assesses its proved oil and gas properties for impairment whenever events or circumstances indicate that the carrying value of the assets may not be recoverable. The impairment test compares future net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded book cost at the end of each period. If the net capitalized cost exceeds net future cash flows, then 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. During 2003, 2002 and 2001, the Company did not record any impairment charges for proved properties.

Gains and losses are recognized on sales of entire interests in proved and unproved properties. Sales of partial interests are generally treated as recoveries of costs.

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.

As of December 31, 2003 and 2002, the balance of other property and equipment was $2,684 and $3,454, respectively. Depreciation expense was approximately $836, $770, and $710 for the years ended December 31, 2003, 2002 and 2001, respectively.

Bank Fees Bank fees are being amortized to interest expense using the interest method over the life of the loan.

Reimbursed Overhead The Company provides various administrative services to its partnerships and owners of certain oil and gas properties for which the Company receives overhead reimbursements. Amounts earned are included as a reduction to general and administrative expense and totaled $5,631, $5,505 and $5,276, for the years ended December 31, 2003, 2002 and 2001, 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

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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, this Statement applies directly to the plug and abandonment liabilities associated with the Company s net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and 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 uses the sales method to record oil revenues whereby revenue is recognized based on the amount of oil sold to purchasers. The Company uses the entitlements method to record natural gas revenues whereby revenue is recognized for the Company s share of natural gas produced, regardless of whether the Company has taken its share of the related revenue. In situations where gas imbalances occur, receivables are valued at current market value each reporting period, while liabilities are generally presented based on the price in effect when the imbalance occurred. As of December 31, 2003 and 2002, the Company was in an under produced imbalance position of approximately 206,000 Mcf and 411,000 Mcf.

Derivative Instruments Whiting is exposed to market risk in the pricing of its oil and gas production. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, transportation availability and price, and general economic conditions. Worldwide political developments have historically also had an impact on oil and gas prices. Periodically, Whiting utilizes oil and gas swaps and forward contracts to mitigate the impact of oil and gas price fluctuations related to its sales of oil and gas. During the years 2003, 2002 and 2001, Whiting entered into a number of oil and gas swaps and forward contracts.

At December 31, 2003, the Company had five commodity swaps or forward contracts outstanding with a fair market value unrealized loss of $2,145 of which $1,317 was recorded as a component of accumulated other comprehensive loss and $828 was recorded as an increase to the deferred tax asset.

At December 31, 2002, the Company had four commodity swaps or forward contracts outstanding with a fair market value unrealized loss of $3,300 of which $1,980 was recorded as a component of accumulated other comprehensive loss and $1,320 was recorded as a reduction to the deferred tax liability.

For the years ended December 31, 2003, 2002, and 2001, Whiting recognized a loss of approximately $8.7 million, a loss of approximately $3.2 million, and a gain of $2.3 million from the settlement of derivative instruments, respectively.

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 and 2002, 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 $585 and a fair value of approximately $2,367 and $1,300, respectively. As of December 31, 2003, the Company recorded an unrealized holding gain of $1,782, correspondingly $1,094 was recorded as a component of accumulated other comprehensive income and $688 was recorded as a decrease to the

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deferred tax asset. As of December 31, 2002, the Company recorded an unrealized holding gain of $715 of which $430 was recorded as a component of accumulated other comprehensive income and $285 was recorded as a deferred tax liability.

Income Taxes 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 purposes. The Company provides deferred federal and state income taxes on all temporary differences between the book and tax basis of the Company s assets and liabilities.

Earnings Per Share Basic net income per common share of stock is calculated by dividing net income by the weighted average 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 of common shares outstanding and other dilutive securities. There were no potentially dilutive securities of the Company outstanding for any of the periods presented.

Industry Segment and Geographic Information The Company operates in one industry segment, which is the exploration, development and production of natural gas and crude oil, and all of the Company s operations are conducted in the United States. Consequently, the Company currently reports as a single industry segment.

New Accounting Pronouncements In June 2001, the Financial Accounting Standards Board (FASB) issued SFAS No. 141, *Business Combinations* which requires the purchase method of accounting for business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FASB issued SFAS No. 142, *Goodwill and Other Intangible Assets*, which discontinues the practice of amortizing goodwill and indefinite lived intangible assets and initiates an annual review for impairment. Intangible assets with a determinable useful life will continue to be amortized over that period. The Company did not change or reclassify contractual mineral rights included in oil and gas properties on the balance sheet upon adoption of SFAS No. 142. The Company believes the current accounting of such mineral rights as part of crude oil and natural gas properties is appropriate under the successful efforts method of accounting. However, there is an alternative view that reclassification of mineral rights to an intangible assets may be necessary. If a reclassification of contractual mineral rights acquired subsequent to July 1, 2001 from oil and gas properties to long term intangible assets is required, then the reclassified amount as of December 31, 2003 and 2002 would be approximately $160.1 million and $161.2 million, respectively. Management does not believe that the ultimate outcome of this issue will have a significant impact on the Company s cash flows, results of operations or financial condition.

In June 2002 the FASB issued SFAS No. 146, *Accounting for Costs Associates with Exit or Disposal Activities*. This Statement addresses financial accounting and reporting for costs associated with exit or disposal activities and nullifies Emerging Issues Task Force (EITF) Issue No. 94-3, *Liability Recognition for Certain Employee Termination Benefits and Other Costs to Exit an Activity (including Certain Costs Incurred in a Restructuring)*. The provisions of this Statement are effective for exit or disposal activities that are initiated after December 31, 2002, with early application encouraged. The adoption of this Statement had no impact on the financial statements.

FASB Interpretation No. 45 (FIN 45), *Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others* was issued in November 2002, by the FASB. FIN 45 requires a guarantor to recognize a liability for the fair value of the obligation it assumes under certain guarantees. Additionally, FIN 45 requires a guarantor to disclose certain aspects of each guarantee, or each group of similar guarantees, including the nature of the guarantee, the maximum

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exposure under the guarantee, the current carrying amount of any liability for the guarantee, and any recourse provisions allowing the guarantor to recover from third parties any amounts paid under the guarantee. The disclosure provisions of FIN 45 are effective for financial statements for both interim and annual periods ending after December 15, 2002. The fair value measurement provisions of FIN 45 are to be applied on a prospective basis to guarantees issued or modified after December 31, 2002. The adoption of this Statement did not have a material impact on the financial statements. Under the disclosure provisions, 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, 2004 increased to 50% of the actual price received in excess of $19.77 per barrel. Approximately 46,000 net barrels of crude oil per month are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. As of December 31, 2003, the Company has paid $3.1 million under this agreement and has accrued an additional $215 as currently payable.

In January 2003, the FASB issued FASB Interpretation No. 46 (as revised in December 2003), *Consolidation of Variable Interest Entities* (FIN 46). FIN 46 clarifies the application of Accounting Research Bulletin No. 51, *Consolidated Financial Statements* to certain entities in which equity investors do not have the characteristics of a controlling financial interest or do not have sufficient equity at risk for the entity to finance its activities without additional subordinated support from other parties. FIN 46 requires existing unconsolidated variable interest entities to be consolidated by their primary beneficiaries if the entities do not effectively disperse risks among parties involved. All companies with interests in variable interest entities created after January 31, 2003, shall apply the provisions of FIN 46 to those entities immediately. The adoption of this Statement had no impact on the Company s financial statements.

In April 2003, the FASB issued SFAS No. 149, *Amendment of Statement 133 on Derivative Instruments and Hedging Activities* to amend and clarify financial accounting and reporting for derivative instruments, including certain derivative instruments embedded in other contracts and for hedging activities. The changes in this statement require that contracts with comparable characteristics be accounted for similarly to achieve more consistent reporting of contracts as either derivative or hybrid instruments. SFAS No. 149 is effective for contracts entered into or modified after June 30, 2003 and will be applied prospectively. The adoption of this Statement had no impact on the financial statements.

In May 2003, the FASB issued SFAS No. 150, *Accounting for Certain Financial Instruments with Characteristics of both Liabilities and Equity* to classify certain financial instruments as liabilities in statements of financial position. The financial instruments are mandatorily redeemable shares, which the issuing company is obligated to buy back in exchange for cash or other assets, put options and forward purchase contracts, instruments that do or may require the issuer to buy back some of its shares in exchange for cash or other assets, and obligations that can be settled with shares, the monetary value of which is fixed, tied solely or predominantly to a variable such as a market index, or varies inversely with the value of the issuers shares. Most of the guidance in SFAS No. 150 is effective for all financial instruments entered into or modified after May 31, 2003, and otherwise is effective at the beginning of the first interim period beginning after June 15, 2003. The adoption of this Statement had no impact on the financial statements.

2. ASSET RETIREMENT OBLIGATIONS

The Company s estimated liability for plugging and abandoning its oil and gas wells and certain obligations for previously owned onshore and offshore facilities in California is discounted using a credit-adjusted risk-free rate of approximately 7%. Upon adoption of SFAS No. 143, the Company recorded an increase to its

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discounted abandonment liability 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 following table provides a reconciliation of the changes in the estimated asset retirement obligation from the amount recorded upon adoption of SFAS No. 143 on January 1, 2003 (including its previously recognized liability in California) through December 31, 2003.

Beginning asset retirement obligation	$ 4,232
SFAS 143 adoption	16,458
Additional liability incurred	996
Accretion expense	1,482
Liabilities settled	(147)
Ending asset retirement obligation	$ 23,021

No revisions have been made to the timing or the amount of the original estimate of undiscounted cash flows during 2003.

3. INVESTMENT IN PARTNERSHIPS

The Company sponsors private oil and gas income and development limited partnerships. The partnership agreements generally provide for a capital contribution by the Company of 8% to 10% of total capital for a 13% to 17% interest in the net revenue of the partnerships. Additionally, Whiting is a general partner in various partnerships which own and operate transportation and gas processing facilities. As a general partner in these partnerships, Whiting may be liable to the extent any such partnerships incur liabilities in excess of the value of its assets.

In 2003, the Company purchased the limited partnership interests in three limited partnerships in which the Company was general partner for $4,453.

4. 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%. All principal and interest on the promissory note are due on November 25, 2005 (see Note 5).

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 and 2002, respectively. On March 31, 2003, Alliant Energy converted its outstanding intercompany balance of $80,931 to equity of the Company. The Company incurred approximately $1.2 million, $10.5 million and $10.2 million, in interest expense related to this note during the years ended December 31, 2003, 2002 and 2001, respectively.

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.

The Company provides general and administrative services to its partnerships for which the partnerships are billed monthly. Amounts so charged are based on flat rates provided for in each respective Partnership

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Agreement. The Company pays operating expenses for its partnerships for which it receives reimbursement. The Company may also advance funds to its partnerships for property development. The amounts due from/to affiliates represent the net amount of advances to partnerships for property development offset by proceeds on sales of property and cash receipts from the sale of oil and gas to be distributed to the partnerships.

5. LONG-TERM DEBT

Long-term debt consisted of the following at December 31, 2003 and 2002:

	2003	2002
Bank borrowings	$ 185,000	$ 185,000
Alliant see Note 4	3,017	80,472

Credit Facility The Company has a $350.0 million credit agreement with a syndicate of banks. At December 31, 2003, the credit agreement provided a borrowing base of $210.0 million with an outstanding principal balance of $185.0 million. On February 17, 2004, the Company repaid $40.0 million of the outstanding principal balance from cash on hand in excess of projected drilling and production needs. The borrowing base under the credit agreement is based on the collateral value of the Company s proved reserves and is subject to redetermination on May 1 and November 1 of each year. If the borrowing base is determined to be lower than the outstanding principal balance then drawn, the Company must immediately pay the difference. The credit agreement provides for interest only payments until December 20, 2005, when the entire amount borrowed is due. Interest accrues, at the Company s option, at either (1) the base rate plus a margin where the base rate is defined as the higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0.25% to 1.0% depending on the ratio of the amounts borrowed to the borrowing base, or (2) at the LIBOR rate plus a margin where the margin varies from 1.5% to 2.25% depending on the ratio of the amounts borrowed to the borrowing base. At December 31, 2003, all amounts outstanding under the credit agreement bore interest at an annual rate of 3.21% through February 6, 2004.

On February 6, 2004, the Company fixed the rate on the outstanding principal balance at an annual rate of 3.2% through August 6, 2004. The credit agreement has covenants that restrict the payment of cash dividends, borrowings, sale of assets, loans to others, investments, merger activity, hedging contracts, liens and certain other transactions without the prior consent of the lenders and requires the Company to maintain certain debt to EBITDAX (as defined in our credit agreement) ratios and a working capital ratio. The credit agreement also precludes the Company from providing any cash to Alliant Energy except for services rendered on an arm s-length basis or for income taxes. The Company was in compliance with the covenants under the credit agreement as of December 31, 2003. The credit agreement is secured by a first lien on substantially all of Whiting s assets.

6. EMPLOYEE BENEFIT PLANS

The Company has a Production Participation Plan for all employees. On an annual basis, management and the Board of Directors allocate interests in oil and gas properties acquired or developed during the year to the plan on a discretionary basis. Once allocated, the interests (not legally conveyed) are fixed and plan participants generally vest ratably over five years. Forfeitures are re-allocated among other Plan participants. Allocations prior to 1995 consisted of 2% 3% overriding royalty interests. Allocations since 1995 have been 2% 5% net revenue interests.

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Payments to participants of the plan are made annually in cash after year end and amounted to $4.4 million, $3.6 million and $4.1 million for 2003, 2002 and 2001, respectively. The Company has estimated the total discounted obligations, including the amounts above, at December 31, 2003 and 2002 as being $12.3 million and $11.7 million, respectively. Plan expense for 2003, 2002 and 2001 was approximately $4.3 million, $5.3 million and $5.6 million, respectively.

The Company s Board of Directors adopted the Whiting Petroleum Corporation 2003 Equity Incentive Plan on September 17, 2003. Two million shares of the Company s common stock have been reserved for issuance under this plan. 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. As of December 31, 2003, no awards had been made under this plan.

The Company also 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 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 is reflected as an increase to additional paid-in capital. The phantom equity plan is now terminated.

The Company also 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 2003, 2002 and 2001 were approximately $665, $529 and $287, respectively. Employer contributions vest ratably at 20% per year over a five year period.

7. COMMITMENTS AND CONTINGENCIES

The Company leases administrative office space under an operating lease arrangement through October 2005. Net rental expense for 2003, 2002, and 2001 amounted to approximately $1,046, $916 and $823, respectively. A summary of future minimum lease payments under this noncancellable-operating lease as of December 31, 2003 is as follows (in thousands):

Year Ending December 31	
2004	$ 1,084
2005	929

Total	$ 2,013

The Company had a $2.5 million unused line of credit with a bank. Interest on the line of credit was prime plus one percent. The line of credit was cancelled in February 2003.

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.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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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 $62 million. The Company has estimated total payments to Alliant will approximate $49 million given the discounting affect of the final payment in 2014. The Company has discounted all cash payments to Alliant at the date of the Tax Separation 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. There is a provision in the Tax Separation Agreement that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in a corresponding adjustment of the Alliant liability. For purposes of this calculation, management has assumed that no such change will occur during the term of this agreement.

8. 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. All income taxes receivable or payable at December 31, 2003 were to/from Alliant Energy. Section 29 tax credits of $5,363 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, Whiting will be paid for the Section 29 credits when Alliant Energy receives the benefit for them. These credits were reported as a credit to additional paid-in capital in 2002.

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

	2003	2002	2001
Expected statutory tax expense at 35%	$ 12,649	$ 4,183	$ 19,018
Research and Section 29 tax credits		(178)	(6,575)
Excess percentage depletion	(216)	(82)	(268)
State tax expense, net of federal benefit	1,516	300	918
	$ 13,949	$ 4,223	$ 13,093

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

	2003	2002
Oil and gas properties	$ (2,893)	$ (32,290)
Production participation plan	2,993	3,020
Available for sale securities	(127)	(285)
Derivative instruments	828	1,320
Tax sharing agreement	11,028	
Abandonment obligations	3,028	
Net operating loss carryforward	3,878	
	$ 18,735	$ (28,235)

The Company s net operating loss will expire in 2023.

9. OIL AND GAS ACTIVITIES

The Company s oil and gas activities are conducted entirely in the United States. Costs incurred in oil and gas producing activities are as follows (in thousands):

	2003	2002	2001
Unproved property acquisition	$ 242	$ 851	$ 105
Proved property acquisition	10,914	140,708	66,024
Development	40,336	23,136	32,073
Exploration	3,186	1,811	793
Subtotal	54,678	166,506	98,995
Asset retirement obligations	996		
Total	$ 55,674	$ 166,506	$ 98,995

During 2003, additions to oil and gas properties of approximately $996 were recorded for the estimated costs related to new wells drilled or acquired.

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

	2003	2002
Proven oil and gas properties	$ 615,764	$ 553,902
Unproven oil and gas properties	1,637	1,593
Accumulated depreciation, depletion and amortization	(191,488)	(152,595)
Oil and gas properties net	$ 425,913	$ 402,900

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

10. 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., and Cawley, Gillespie & Associates, Inc. and R. A. Lenser & 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.

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The Company s oil and gas reserves are attributable solely to properties within the United States. A summary of the Company s changes in quantities of proved oil and gas reserves for the years ended December 31, 2003, 2002 and 2001, are as follows:

	Oil (Mbbls)	Gas (Mmcf)
Balance January 1, 2001	19,121	157,521
Extensions and discoveries	1,086	9,320
Sales of minerals in place	(677)	(6,045)
Purchases of minerals in place	945	89,760
Production	(2,088)	(19,751)
Revisions to previous estimates	(3,582)	(3,284)
Balance December 31, 2001	14,805	227,521
Extensions and discoveries	473	2,346
Sales of minerals in place		(953)
Purchases of minerals in place	15,244	58,381
Production	(2,319)	(21,366)
Revisions to previous estimates	1,255	(29,941)
Balance December 31, 2002	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
Proved developed reserves:		
December 31, 2001	11,046	136,817
December 31, 2002	23,784	167,618
December 31, 2003	26,157	171,881

As discussed in Note 6 Employee Benefit Plans, all of the Company s employees participate in the Company s production participation plan. The reserve disclosures above include oil and gas reserve volumes that have been allocated to the production participation plan. 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 gas production allocated to the plan.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with the provisions of SFAS No. 69. Future cash inflows were computed by applying prices at year end to estimated future production. Future production and development costs are computed by estimating the expenditures to be incurred in developing and producing the proved oil and gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions.

Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows relating to proved oil and gas reserves, less the tax basis of properties involved. Future income

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YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

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

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

	2003	2002	2001
Future cash flows	$ 2,297,935	$ 1,854,886	$ 880,890
Future production costs	(879,390)	(677,146)	(379,732)
Future development costs	(66,326)	(65,440)	(75,575)
Future income tax expense	(336,165)	(270,516)	(62,025)
Future net cash flows	1,016,054	841,784	363,558
10% annual discount for estimated timing of cash flows	(426,490)	(365,755)	(151,823)
Standardized measure of discounted future net cash flows	$ 589,564	$ 476,029	$ 211,735

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 $145 in 2003 and $1,300 in 2002 and $0 in 2001, respectively.

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

	2003	2002	2001
		(in thousands)	
Beginning of year:	$ 476,029	$ 211,735	$ 519,197
Sale of oil and gas produced, net of production costs	(121,827)	(80,337)	(87,273)
Sales of minerals in place		(739)	(11,200)
Net changes in prices and production costs	108,115	212,191	(528,096)

Extensions, discoveries and improved recoveries	47,183	6,587	17,511
Development costs-net	(886)	(11,328)	(3,322)
Purchases of mineral in place	16,745	241,798	84,613
Revisions of previous quantity estimates	43,679	(36,164)	(16,205)
Net change in income taxes	(42,082)	(116,854)	183,051
Accretion of discount	62,901	24,786	73,516
Changes in production rates and other	(293)	24,354	(20,057)
End of year	$ 589,564	$ 476,029	$ 211,735

Average wellhead prices in effect at December 31, 2003, 2002 and 2001 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows (in thousands):

	2003	2002	2001
Oil (per Bbl)	$ 29.43	$ 28.21	$ 17.30
Gas (per Mcf)	$ 5.52	$ 4.39	$ 2.72

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

YEARS ENDED DECEMBER 31, 2003, 2002, AND 2001

(In thousands, except per share data)

11. QUARTERLY FINANCIAL DATA (UNAUDITED)

The following is a summary of the unaudited financial data for each quarter for the years ended December 31, 2003, 2002, and 2001 (in thousands except per share data) (in thousands):

	Three Months Ended			
	March 31, 2003	June 30, 2003	September 30, 2003	December 31, 2003
Year ended December 31, 2003:				
Oil and gas sales	$ 49,483	$ 41,883	$ 42,272	$ 42,093
Income (loss) before income tax and cumulative effect of change in accounting principle	11,935	11,481	12,885	(162)
Cumulative effect of change in accounting principle	(3,905)			
Net income (loss)	3,559	7,053	7,989	(316)
Basic net income (loss) per share	0.19	0.38	0.43	(0.02)

	Three Months Ended			
	March 31, 2002	June 30, 2002	September 30, 2002	December 31, 2002
Year ended December 31, 2002:				
Oil and gas sales	$ 20,190	$ 29,552	$ 34,657	$ 38,310
Income (loss) before income tax	(2,977)	3,277	6,191	5,461
Net income	(1,822)	2,050	3,877	3,624
Basic net income (loss) per share	(0.10)	0.11	0.21	0.19

12. SUBSEQUENT EVENT

On February 2, 2004, Whiting announced that the Company entered into a definitive merger agreement to acquire Equity Oil Company. The merger agreement provides for a stock-for-stock merger under which Equity shareholders will receive a fixed exchange ratio of 0.185 shares of Whiting common stock for each share of Equity common stock that they own. In addition, Whiting will assume approximately $29 million of Equity debt. The merger is subject to the approval of shareholders owning two-thirds of the outstanding Equity shares and other customary closing conditions. Equity intends to call a special meeting of its shareholders during the second quarter of 2004 to consider and vote on the merger. The Company expects to complete the merger as soon as practicable following approval by Equity s shareholders.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2004 (Unaudited) AND DECEMBER 31, 2003

(In thousands)

	September 30, 2004	December 31, 2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 17,361	$ 53,585
Accounts receivable trade, net	35,322	24,020
Prepaid expenses and other	6,488	2,666
Total current assets	59,171	80,271
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	1,193,090	615,764
Unproved properties	4,325	1,637
Other property and equipment	3,616	2,684
Total property and equipment	1,201,031	620,085
Less accumulated depreciation, depletion and amortization	(225,275)	(192,794)
Total property and equipment-net	975,756	427,291
OTHER LONG-TERM ASSETS	19,624	9,988
DEFERRED INCOME TAX ASSET		18,735
TOTAL	$ 1,054,551	$ 536,285

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

AS OF SEPTEMBER 30, 2004 (Unaudited) AND DECEMBER 31, 2003

(In thousands)

	September 30, 2004	December 31, 2003
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 23,280	$ 15,918
Oil and gas sales payable	4,051	2,406
Accrued employee benefits	4,788	5,275
Production taxes payable	7,580	2,574
Derivative liability	9,850	2,145
Income taxes and other liabilities	200	693
Current portion of long-term debt	50,000	
Total current liabilities	99,749	29,011
ASSET RETIREMENT OBLIGATIONS	30,502	23,021
PRODUCTION PARTICIPATION PLAN LIABILITY	8,833	7,868
TAX SHARING LIABILITY	30,590	28,790
LONG-TERM DEBT	538,827	188,017
DEFERRED INCOME TAX LIABILITY	11,153	
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY:		
Common stock, $.001 par value; 75,000,000 shares authorized, 21,100,347 and 18,750,000 shares issued and outstanding	21	19
Additional paid-in capital	216,120	170,367
Accumulated other comprehensive loss	(6,050)	(223)
Deferred compensation	(2,035)	
Retained earnings	126,841	89,415
Total stockholders equity	334,897	259,578
TOTAL	$ 1,054,551	$ 536,285

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

UNAUDITED CONSOLIDATED STATEMENTS OF INCOME

FOR THE THREE MONTHS AND NINE MONTHS ENDED SEPTEMBER 30, 2004 AND 2003

(In thousands, except per share data)

	Three Months Ended September 30,		Nine Months Ended September 30,	
	2004	2003	2004	2003
REVENUES:				
Oil and gas sales	$ 65,898	$ 42,272	$ 166,408	$ 133,638
Loss on oil and gas hedging activities	(2,040)	(151)	(3,615)	(8,953)
Gain on sale of marketable securities	2,380		4,762	
Gain on sale of oil and gas properties	1,000		1,000	
Interest income and other	52	87	186	180
Total	67,290	42,208	168,741	124,865
COSTS AND EXPENSES:				
Lease operating	12,957	11,288	34,650	32,108
Production taxes	3,950	2,560	10,168	8,134
Depreciation, depletion and amortization	13,010	10,212	34,500	30,675
Exploration and impairment	3,766	280	4,686	1,015
General and administrative	6,117	3,126	14,191	9,522
Interest expense	4,172	1,856	9,591	7,110
Total costs and expenses	43,972	29,322	107,786	88,564
INCOME BEFORE INCOME TAXES AND CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	23,318	12,886	60,955	36,301
INCOME TAX EXPENSE:				
Current	400	208	400	650
Deferred	8,601	4,688	23,129	13,144
Total income tax expense	9,001	4,896	23,529	13,794
INCOME FROM CONTINUING OPERATIONS	14,317	7,990	37,426	22,507
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE (See Note 4)				(3,905)
NET INCOME	$ 14,317	$ 7,990	$ 37,426	$ 18,602
Earnings per share from continuing operations, basic and diluted	$ 0.70	$ 0.43	$ 1.93	$ 1.20
Cumulative change in accounting principle				(0.21)

NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 0.70	$ 0.43	$ 1.93	$ 0.99
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	20,516	18,750	19,341	18,750
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	20,554	18,750	19,370	18,750

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS EQUITY AND COMPREHENSIVE INCOME

FOR THE YEAR ENDED DECEMBER 31, 2003 AND THE NINE MONTHS ENDED SEPTEMBER 30, 2004 (Unaudited)

(In thousands)

	Common Stock							
	Shares	Amount	Additional Paid-in Capital	Retained Earnings	Accumulated Other Comprehensive Income (Loss)	Deferred Compensation	Total Stockholders Equity	Comprehensive Income
BALANCES January 1, 2003	18,750	$ 19	$ 53,219	$ 71,130	$ (1,550)	$	$ 122,818	
Net income				18,285			18,285	$ 18,285
Unrealized net gain on marketable 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	89,415	(223)		259,578	$ 19,612
Net income (unaudited)				37,426			37,426	$ 37,426
Change in fair value of marketable securities for sale (unaudited)					3,741		3,741	3,741
Realized net gain on marketable securities for sale (unaudited)					(4,835)		(4,835)	(4,835)
Change in derivative instrument fair value (unaudited)					(4,733)		(4,733)	(4,733)
Issuance of stock (unaudited)	2,237	2	43,296				43,298	
Deferred compensation stock issued (unaudited)	113		2,457			(2,457)		
Amortization of deferred compensation (unaudited)						422	422	
BALANCES September 30, 2004 (unaudited)	21,100	$ 21	$ 216,120	$ 126,841	$ (6,050)	$ (2,035)	$ 334,897	$ 31,599

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

UNAUDITED CONSOLIDATED STATEMENTS OF CASH FLOWS

FOR THE NINE MONTHS ENDED SEPTEMBER 30, 2004 AND 2003 (in thousands)

	2004	2003
CASH FLOWS FROM OPERATING ACTIVITIES:		
Net income	$ 37,426	$ 18,601
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	34,500	30,674
Deferred income taxes	23,129	13,144
Amortization of debt issuance costs and debt discount	1,025	860
Accretion of tax sharing agreement	1,800	
Amortization of deferred compensation	422	
Gain on sale of marketable securities	(4,835)	
Gain on sale of oil and gas properties	(1,000)	
Impairment of oil and gas properties	2,152	
Cumulative change in accounting principle		3,905
Changes in assets and liabilities:		
Accounts receivable	(6,466)	1,018
Income taxes and other receivable		204
Other assets	(3,652)	1,452
Asset retirement obligations	(321)	(128)
Production participation plan liability	542	(650)
Other current liabilities	12,144	5,874
Net cash provided by operating activities	96,866	74,954
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(445,340)	(6,466)
Drilling capital expenditures	(52,782)	(26,603)
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		(4,453)
Net cash used by investing activities	(491,958)	(37,522)
CASH FLOWS FROM FINANCING ACTIVITIES:		
Advances from Alliant		460
Issuance of long-term debt	583,890	
Payments on long-term debt	(214,000)	
Debt issuance costs	(11,022)	(218)
Net cash provided (used) by financing activities	358,868	242
NET CHANGE IN CASH AND CASH EQUIVALENTS	(36,224)	37,674
CASH AND CASH EQUIVALENTS:		
Beginning of period	53,585	4,833

End of period	$ 17,361	$ 42,507
SUPPLEMENT CASH FLOW DISCLOSURES:		
Cash paid for income taxes	$ 885	$ 446
Cash paid for interest	$ 3,592	$ 5,726
NONCASH FINANCING ACTIVITIES:		
Issuance of common stock for Equity Oil Company common stock	$ 43,298	
Alliant debt converted to equity	$	$ 80,931

See notes to unaudited consolidated financial statements.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

SEPTEMBER 30, 2004

(In thousands, except per share data)

1. BASIS OF PRESENTATION

Description of Operations Whiting Petroleum Corporation (Whiting or the Company) 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 initial public offering of Whiting s common stock, the Company in effect split its common stock, issuing 18,330 shares for the 1 previously held by Alliant Energy. All periods presented have been adjusted to reflect the current capital structure. Whiting acquires, develops and explores for producing oil and gas properties primarily in the Gulf Coast/Permian Basin, Rocky Mountains, Michigan, and Mid-Continent regions of the United States.

Consolidated Financial Statements The unaudited 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 is the sole general partner. The financial statements have been prepared in accordance with generally accepted accounting principles for interim financial reporting. All significant intercompany balances and transactions have been eliminated in consolidation. In the opinion of management, all adjustments considered necessary for a fair presentation have been included. Except as disclosed herein, there has been no material change to the information disclosed in the notes to consolidated financial statements included in Whiting s Annual Report on Form 10-K for the year ended December 31, 2003. It is recommended that these unaudited consolidated financial statements be read in conjunction with the audited consolidated financial statements and notes included in the Company s Form 10-K.

Earnings Per Share Basic net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding during each period. Diluted net income per common share of stock is calculated by dividing net income by the weighted average of common shares outstanding and other dilutive securities. The only securities considered dilutive are the Company s unvested restricted stock awards. The dilutive effect of these securities was immaterial to the calculation.

2. DERIVATIVE FINANCIAL INSTRUMENTS

Whiting is exposed to market risk in the pricing of its oil and gas production. Historically, prices received for oil and gas production have been volatile because of seasonal weather patterns, supply and demand factors, worldwide political factors and general economic conditions. Periodically, Whiting utilizes traditional swap and collar arrangements to mitigate the impact of oil and gas price fluctuations related to its sales of oil and gas. The Company attempts to qualify the majority of these instruments as cash flow hedges for accounting purposes.

During the first nine months of 2004 and 2003, the Company recognized losses of $3,615 and $8,953, respectively, related to its hedging activities. In addition, at September 30, 2004, Whiting s remaining cash flow hedge positions resulted in a pre-tax liability of $9,850 of which $6,050 was recorded as a component of accumulated other comprehensive income and $3,000 was recorded as a decrease to the deferred tax liability. See Note 5 for restrictions in our credit agreement relating to hedging activities.

3. MARKETABLE SECURITIES

As of December 31, 2003, the Company held an investment in a publicly traded security classified as available-for-sale (included in other long term-assets). The original cost to the Company was $585. During

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

SEPTEMBER 30, 2004

(In thousands, except per share data)

the nine months ended September 30, 2004, the Company sold its holdings for $5,420 realizing a gain on sale of $4,835. As of December 31, 2003, the Company recorded an unrealized holding gain of $1,782 of which $1,094 was recorded as a component of accumulated other comprehensive income and $688 was recorded as a decrease to the deferred tax asset.

4. 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. 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, this Statement applies directly to the plug and abandonment liabilities associated with the Company s net working interest in well bores. The additional carrying amount is depleted over the estimated 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 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 upon settlement.

The Company s estimated liability for plugging and abandoning its oil and natural gas wells and certain obligations for onshore and offshore facilities in California is discounted using a credit-adjusted risk-free rate of approximately 7%. 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 following table provides a reconciliation of the Company s asset retirement obligations for the nine months ended September 30, 2004 and the year ended December 31, 2003.

	Nine Months Ended September 30, 2004	Year Ended December 31, 2003
Beginning asset retirement obligation	$ 23,021	$ 4,232
SFAS 143 adoption		16,458
Additional liability incurred	6,588	996
Accretion expense	1,214	1,482
Liabilities settled	(321)	(147)
Ending asset retirement obligation	$ 30,502	$ 23,021

No revisions have been made to the timing or the amount of the original estimate of undiscounted cash flows during 2003 or the first nine months of 2004.

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

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(In thousands, except per share data)

5. LONG-TERM DEBT

Long-term debt consisted of the following at September 30, 2004 and December 31, 2003:

	September 30, 2004	December 31, 2003
7 1/4% Senior Subordinated Notes due 2012	$ 150,697	$
Credit Facility	$ 435,000	$ 185,000
Alliant	$ 3,130	$ 3,017
Total debt	$ 588,827	$ 188,017
Less current portion of long-term debt	$ (50,000)	$
Long-term debt	$ 538,827	$ 188,017

Credit Facility On September 23, 2004, Whiting Oil and Gas Corporation entered into an amended and restated $750.0 million credit agreement with a syndicate of banks. The new credit agreement increases the Company s borrowing base to $480.0 million from $195.0 million under the prior credit agreement. The borrowing base under the credit agreement is determined in the discretion of the lenders based on the collateral value of the proved reserves that have been mortgaged to the lenders and is subject to regular redetermination on May 1 and November 1 of each year as well as special redeterminations described in the credit agreement. On September 23, 2004, Whiting Oil and Gas Corporation borrowed $400.0 million under the credit agreement in order to (i) refinance the entire outstanding balance under the prior credit agreement and (ii) fund its $345.0 million acquisition of oil and natural gas producing properties from CrownQuest Operating LLC. On September 30, 2004, an additional $35.0 million was borrowed to fund an additional acquisition.

The credit agreement provides for interest only payments until September 23, 2008, when the entire amount borrowed is due. In addition, the credit agreement provides that Whiting Oil and Gas Corporation will make principal payments under the credit agreement by May 1, 2005 to reduce the principal balance to $385.0 million. Whiting Oil and Gas Corporation may, throughout the four year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect from time to time. Interest accrues, at Whiting Oil and Gas Corporation s option, at either (1) the base rate plus a margin where the base rate is defined as the higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0% to 0.50% 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 Corporation has consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.250% 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.

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 contracts, 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 of greater than 1 to 1. The credit agreement also requires the Company to hedge at least 60% but not more than 75% of its total forecasted proved developed producing production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps, with a minimum floor price of $35 per barrel of oil or $4.50 per million British Thermal Units (MMBtu). After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to

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a maximum of 75% of our forecasted proved developed producing production. In addition, while the credit agreement allows the Company s subsidiaries to make payments to the Company so that it may pay interest on its senior subordinated notes, it does not allow the Company s subsidiaries to make payments to it to pay principal on the senior subordinated notes. The Company was in compliance with its covenants under the credit agreement as of September 30, 2004. The credit agreement is secured by a first lien on substantially all of Whiting Oil and Gas Corporation s assets. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement, Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for its guarantee and Equity Oil Company has mortgaged substantially all of its assets as security for its guarantee.

7 1/4% Senior Subordinated Notes due 2012 On May 11, 2004, the Company issued, in a private placement, $150.0 million aggregate principal amount of its 7 1/4% senior subordinated notes due 2012. The net proceeds of the offering were used to refinance debt outstanding under the Company s credit agreement. The notes were issued at 99.26% of par and the associated discount is being amortized to interest expense over the term of the notes. On July 12, 2004, the Company completed an exchange offer in which it issued $150.0 million aggregate principal amount of new 7 1/4% senior subordinated notes due 2012 registered under the Securities Act of 1933 in exchange for the old notes. The notes are unsecured obligations of the Company and are subordinated to all of the Company s senior debt. The indenture governing the notes contains various restrictive covenants that 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 Corporation s credit agreement restricts the ability of the Company s subsidiaries to make payments to the Company. The Company was in compliance with these covenants as of September 30, 2004. Three of the Company s 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. All of the Company s subsidiaries other than the Guarantors are minor 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, we entered into an interest rate swap contract to hedge the fair value of $75 million of our 7 1/4% 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 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 million for the six month period. As of September 30, 2004, we have recorded a long term derivative asset of $1.7 million related to the interest rate swap, which has been designated as a fair value hedge, with a corresponding debt increase.

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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Long-Term Debt Payable to Alliant Energy 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 promissory note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due 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 the first quarter of 2003. On March 31, 2003, Alliant Energy converted its outstanding intercompany balance of $80.9 million to equity of the Company.

6. EQUITY INCENTIVE PLAN

The Company s Board of Directors adopted the Whiting Petroleum Corporation 2003 Equity Incentive Plan on September 17, 2003. Two million shares of the Company s common stock have been reserved for issuance under this plan. 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 the first three quarters of 2004, the Company granted 112,921 shares of restricted stock under this plan. The shares of restricted stock were recorded at fair value of $2.5 million and are being amortized to general and administrative expense over their three year vesting period.

7. PRODUCTION PARTICIPATION PLAN

The Company maintains a Production Participation Plan for all employees. On an annual basis, interests in oil and gas properties acquired or developed during the year are allocated to the plan on a discretionary basis. Once allocated, the interests (not legally conveyed) are fixed and plan participants generally vest ratably over five years. Forfeitures are re-allocated among other Plan participants. Allocations prior to 1995 consisted of 2% 3% overriding royalty interests. Allocations since 1995 have been 2% 5% net revenue interests. Payments to participants of the plan are made annually in cash after year end.

Effective April 23, 2004, the Production Participation Plan was amended and restated. Specifically, the plan was amended to (1) provide that, for years 2004 and beyond, employees will vest at a rate of 20% per year with respect to the income allocated to the plan for such year; (2) provide that employees will become fully vested at age 65, regardless of when their interests would otherwise vest; and (3) provide that, for pools for years 2004 and beyond, if there are forfeitures, the interests will inure to the benefit of the Company.

8. 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

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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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 90% of 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 $62 million. The Company has estimated total payments to Alliant will approximate $49 million given the discounting affect of the final payment in 2014. The Company has discounted all cash payments to Alliant at the date of the Tax Separation 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 the first nine months of 2004, the Company recognized $1.8 million of accretion expense which is included as a component of interest expense.

There is a provision in the Tax Separation Agreement that if tax rates were to change (increase or decrease), the tax benefit or detriment would result in a corresponding adjustment of the Alliant liability. For purposes of this calculation, management has assumed that no such change will occur during the term of this agreement.

9. ACQUISITIONS

Permian Basin Properties

On September 23, 2004, we 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 our bank credit agreement.

For the year ended December 31, 2003, these properties reported revenues in excess of direct operating expenses of $72.1 million. As of October 1, 2004, these properties had 250.0 Bcfe of estimated proved reserves, of which 17.8% were natural gas and 58.9% were classified as proved developed, and had a pre-tax PV10 value of estimated proved reserves of $673.6 million. The estimated October 2004 average daily production for these properties is approximately 36.4 MMcfe, implying an average reserve life of 18.8 years. We operate approximately 72% of the average daily production from these properties.

Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our 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.

For the year ended December 31, 2003, Equity reported income from continuing operations of $2.4 million, net cash provided by operating activities of $11.5 million and production of 6.6 Bcfe (45% natural gas). As of October 1, 2004, Equity had 103.6 Bcfe of estimated proved reserves, of which 40.6% were natural gas and 69% were classified as proved developed, and had a pre-tax PV10% value of estimated proved reserves of approximately $217.6 million. The estimated October 2004 average daily production from these properties is approximately 16.1 MMcfe, implying an average reserve life of 17.6 years.

WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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Based on the purchase price of $72.6 million and estimated proved reserves of 87.7 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $0.83 per Mcfe of estimated proved reserves.

Other Cash Acquisitions of Properties

On August 13, 2004, we acquired interests in four producing oil and gas fields in Colorado and Wyoming from an undisclosed seller. The purchase price was $44.2 million in cash and was funded under our bank credit agreement. We operate two of the fields and have an 84% average working interest in those fields. As of October 1, 2004, these interests had 40.1 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 8.6 MMcfe, implying an average reserve life of 12.7 years. Based on the purchase price of $44.2 million and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.11 per Mcfe of estimated proved reserves.

On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah from an undisclosed seller. The purchase price was $35.0 million in cash and was funded under our bank credit agreement. As of October 1, 2004, these interests had 32.6 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 6.1 MMcfe, implying an average reserve life of 14.7 years. Based on the purchase price of $35.0 million and estimated proved reserves of 30.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.14 per Mcfe of estimated proved reserves.

On August 16, 2004, we acquired interests in five fields in Louisiana and South Texas from Delta Petroleum Corporation. The purchase price was $19.3 million in cash and was funded under our bank credit agreement. We operate two of the fields and have a 93% average working interest in those fields. As of October 1, 2004, these interests had 13.9 Bcfe of estimated proved reserves and estimated October 2004 average daily production of 3.5 MMcfe, implying an average reserve life of 11.0 years. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcfe on the effective date of the acquisition, we acquired these properties for approximately $1.61 per Mcfe 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 our results from the respective acquisition dates noted above. The table below summarizes the preliminary allocation of the purchase price of each 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	$ 98,500
Debt assumed		29,000	
Stock issued		43,298	
Total	$ 345,000	$ 72,554	$ 98,500
Allocation of Purchase Price:			
Working capital		$ 3,779	
Oil and gas properties	$ 345,000	82,776	$ 98,500
Deferred income taxes		(10,418)	
Other non-current liabilities		(3,583)	
Total	$ 345,000	$ 72,554	$ 98,500

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

NOTES TO UNAUDITED CONSOLIDATED FINANCIAL STATEMENTS

SEPTEMBER 30, 2004

(In thousands, except per share data)

The following table reflects the unaudited pro forma results of operations for the year ended December 31, 2003 and for the three and nine month periods ended September 30, 2004 as though the above acquisitions had occurred on the first day of each period presented. The pro forma amounts for the three and nine month periods ended September 30, 2004 include only the activity from the beginning of the period to the closing date of the acquisitions. (in thousands, except per share amounts):

		Pro Forma			
	Historical Whiting	Permian Basin	Equity Oil	Other Cash Acquisitions	Pro Forma Consolidated
Year ended December 31, 2003					
Total revenues	$ 167,381	$ 91,246	$ 27,825	$ 28,592	$ 315,044
Net income from continuing operations	22,190	19,028	6,050	3,823	51,091
Net income	18,285	19,028	6,050	3,823	47,186
Net income per common share-basic and diluted	0.98	0.91	0.29	0.18	2.25
Three months ended September 30, 2004					
Total revenues	$ 67,290	$ 19,300	$ 1,489	$ 6,123	$ 94,202
Net income	14,317	4,649	377	1,205	20,548
Net income per common share-basic and diluted	0.70	0.22	0.02	0.06	0.98
Three months ended September 30, 2003					
Total revenues	$ 42,208	$ 21,476	$ 6,705	$ 7,117	$ 77,506
Net income	7,990	4,733	1,408	955	15,086
Net income per common share-basic and diluted	0.43	0.23	0.07	0.05	0.72
Nine months ended September 30, 2004					
Total revenues	$ 168,741	$ 58,443	$ 15,980	$ 23,553	$ 266,717
Net income	$ 37,426	$ 11,614	$ 4,047	$ 4,457	$ 57,545
Net income per common share-basic and diluted	$ 1.93	$ 0.55	$ 0.19	$ 0.21	$ 2.74
Nine months ended September 30, 2003					
Total revenues	$ 124,865	$ 74,070	$ 20,101	$ 21,723	$ 240,759
Net income from continuing operations	22,507	16,809	3,866	3,092	46,274
Net income	18,602	16,809	3,866	3,092	42,369
Net income per common share-basic and diluted	0.99	0.80	0.18	0.15	2.02

10. QUARTERLY FINANCIAL DATA

The following is a summary of the unaudited financial data for each quarter for the nine months ended September 30, 2004 (in thousands, except per share data):

	Three Months Ended		
	March 31, 2004	June 30, 2004	September 30, 2004
Nine months ended September 30, 2004:			
Oil and gas sales	$ 47,636	$ 52,874	$ 65,898
Net income	9,638	13,471	14,317
Basic net income per share	0.51	0.72	0.70

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Board of Directors and Stockholders of

Whiting Petroleum Corporation:

We have audited the accompanying statements of revenues and direct operating expenses of the properties (the Permian Basin Acquisition Properties) acquired by Whiting Petroleum Corporation (the Company) from CQ Acquisition Partners I, L.P., SPA-CQAP II, Enerquest Oil & Gas, Ltd. and Baytech, L.L.P. for each of the three years in the period ended December 31, 2003. These statements are the responsibility of the Company s management. Our responsibility is to express an opinion on these statements based on our audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall presentation of the statements. We believe that our audits provide a reasonable basis for our opinion.

The accompanying statements were prepared for the purpose of complying with the rules and regulations of the Securities and Exchange Commission as described in Note 1 to the statements and are not intended to be a complete presentation of the Company s interests in the properties described above.

In our opinion, the statements referred to above present fairly, in all material respects, the revenues and direct operating expenses, described in Note 1, of the Permian Basin Acquisition Properties for each of the three years in the period ended December 31, 2003, in conformity with accounting principles generally accepted in the United States of America.

/s/ DELOITTE & TOUCHE LLP

Denver, Colorado

October 15, 2004

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PERMIAN BASIN ACQUISITION PROPERTIES

STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES (in thousands)

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001 AND THE SIX MONTHS ENDED

JUNE 30, 2004 and 2003 (UNAUDITED)

	Six Months Ended June 30,		Year Ended December 31,		
	2004	2003	2003	2002	2001
	(Unaudited)				
REVENUES Oil and gas production	$ 39,143	$ 52,594	$ 91,246	$ 61,903	$ 69,682
DIRECT OPERATING EXPENSES:					
Lease operating expense	8,244	6,900	14,031	11,252	10,755
Production taxes	2,317	2,899	5,159	3,350	4,149
Total direct operating expenses	10,561	9,799	19,190	14,602	14,904
Revenues in excess of direct operating expenses	$ 28,582	$ 42,795	$ 72,056	$ 47,301	$ 54,778

See accompanying notes to the Statements of Revenues and Direct Operating Expenses.

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PERMIAN BASIN ACQUISITION PROPERTIES

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001 AND THE SIX MONTHS ENDED

JUNE 30, 2004 and 2003 (UNAUDITED)

1. BASIS OF PRESENTATION

On September 23, 2004, Whiting Petroleum Corporation (the Company) completed its acquisition of interests in seventeen oil and natural gas fields located in the Permian Basin of West Texas and Southeast New Mexico from CQ Acquisition Partners I, L.P., SPA-CQAP II, Enerquest Oil & Gas, Ltd. and Baytech, L.L.P. (collectively, the Sellers) for $345 million. The properties are referred to herein as the Permian Basin Acquisition Properties .

The accompanying statements of revenues and direct operating expenses were derived from the historical accounting records of the Sellers and prior operators and reflect the revenues and direct operating expenses of the Permian Basin Acquisition Properties. Such amounts may not be representative of future operations. The statements do not include depreciation, depletion and amortization, general and administrative expenses, income taxes or interest expense as these costs may not be comparable to the expenses expected to be incurred by the Company on a prospective basis.

The Sellers used the sales method to record oil revenue, whereby revenue is recognized based on the amount of oil sold to purchasers. With respect to the gas sales, the entitlements method was used for recording revenues. Under this approach, revenue is recognized for the Sellers share of natural gas produced regardless of whether the Sellers had taken its share of the related production. The effect on revenues of production imbalances is not material. Direct operating expenses include payroll, leases and well repairs, production taxes, maintenance, utilities and other direct operating expenses.

The process of preparing financial statements in conformity with generally accepted principles requires the use of estimates and assumptions regarding certain types of revenues and expenses. Such estimates primarily relate to unsettled transactions and events as of the date of the financial statements. Accordingly, upon settlement, actual results may differ from estimated amounts.

Historical financial statements reflecting financial position, results of operations and cash flows required by generally accepted accounting principles are not presented as such information is not readily available on an individual property basis and not meaningful to the Permian Basin Acquisition Properties. Accordingly, the historical statements of revenue and direct operating expenses are presented in lieu of the financial statements required under Rule 3-05 of the Securities and Exchange Commission Regulation S-X.

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PERMIAN BASIN ACQUISITION PROPERTIES

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001 AND THE SIX MONTHS ENDED

JUNE 30, 2004 and 2003 (UNAUDITED)

2. SUPPLEMENTAL DISCLOSURES OF OIL AND GAS PRODUCING ACTIVITIES (UNAUDITED)

Reserve Quantities The following table summarizes the estimated quantities of proved oil and gas reserves of the Permian Basin Acquisition Properties. These amounts were derived from reserve estimates prepared by Cawley, Gillespie & Associates, Inc. as of July 1, 2004, adjusted only for production in prior periods. 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. The oil and gas reserves stated below are attributable solely to properties within the United States.

	Oil (Mbbls)	Gas (Mmcf)
Balance January 1, 2001	39,127	76,515
Production	(1,415)	(8,682)
Balance December 31, 2001	37,712	67,833
Production	(1,948)	(5,333)
Balance December 31, 2002	35,764	62,500
Production	(2,166)	(5,878)
Balance December 31, 2003	33,598	56,622
Production	(777)	(2,413)
Balance June 30, 2004	32,821	54,209
Proved developed reserves:		
December 31, 2001	23,157	52,001
December 31, 2002	21,209	46,668
December 31, 2003	19,043	40,790
June 30, 2004	18,266	38,377

Standardized Measure of Discounted Future Net Cash Flows The standardized measure of discounted future net cash flows relating to proved oil and gas reserves and the changes in standardized measure of discounted future net cash flows relating to proved oil and gas reserves were prepared in accordance with the provisions of SFAS No. 69. Future cash inflows were computed by applying prices at year end to estimated future production, less estimated future expenditures (based on year end costs) to be incurred in developing and producing the proved reserves, less estimated future income tax expense. Future income tax expenses are calculated by applying appropriate year-end tax rates to future pretax net cash flows, less the tax basis of properties involved. 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 Permian Basin Acquisition Properties (in thousands).

	2003	2002	2001
Future cash flows	$ 1,210,949	$ 1,187,059	$ 727,071
Future production costs	(416,440)	(429,143)	(414,835)
Future development costs	(73,031)	(90,082)	(95,872)
Future income tax expense	(110,581)	(89,874)	
Future net cash flows	610,897	577,960	216,364
10% annual discount for estimated timing of cash flows	(304,410)	(287,997)	(107,814)
Standardized measure of discounted future net cash flows	$ 306,487	$ 289,963	$ 108,550

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PERMIAN BASIN ACQUISITION PROPERTIES

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSES

FOR THE YEARS ENDED DECEMBER 31, 2003, 2002 and 2001 AND THE SIX MONTHS ENDED

JUNE 30, 2004 and 2003 (UNAUDITED)

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

	2003	2002	2001
Beginning of year:	$ 289,963	$ 108,550	$ 376,220
Sale of oil and gas produced, net of production costs	(72,056)	(47,301)	(54,778)
Net changes in prices and production costs	48,413	257,159	(368,691)
Development costs	17,051	5,790	3,698
Net change in income taxes	(10,389)	(45,090)	103,471
Accretion of discount	33,505	10,855	48,630
End of Year	$ 306,487	$ 289,963	$ 108,550

Average wellhead prices in effect at December 31, 2003, 2002 and 2001 inclusive of adjustments for quality and location used in determining future net revenues related to the standardized measure calculation are as follows (in thousands):

	2003	2002	2001
Oil (per Bbl)	$ 28.29	$ 27.04	$ 15.88
Gas (per Mcf)	4.60	3.52	1.89

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GLOSSARY OF OIL AND NATURAL GAS TERMS

We have included below the definitions for certain oil and natural gas terms used in this prospectus:

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 prospectus in reference to oil and other liquid hydrocarbons.

Bcf One billion cubic feet of natural gas.

Bcfe One billion cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

Boe Barrels of oil equivalent, determined using the ratio of six thousand cubic feet of natural gas to one barrel of oil.

Bopd Barrels of oil 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.

horizontal re-entry well A new well in which a pre-existing wellbore is used as the starting point of a new horizontal borehole. Drilling a horizontal re-entry well typically involves milling a hole in the casing of the pre-existing wellbore and drilling hundreds or thousands of feet from the pre-existing wellbore.

Mbo One thousand barrels of oil.

Mcf One thousand cubic feet of natural gas.

*Mcf/*d One Mcf per day.

Mcfe One thousand cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

*Mcfe/*d One Mcfe per day.

MMbbls millions of barrels of oil or other liquid hydrocarbons.

MMboe One million barrels of oil equivalent.

MMbtu One million British Thermal Units.

MMcf One million cubic feet of natural gas.

MMcf/d One MMcf per day.

MMcfe One million cubic feet equivalent, determined using the ratio of six Mcf of natural gas to one Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d One MMcfe per day.

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%.

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 a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

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7,500,000 Shares

Whiting Petroleum Corporation

Common Stock

PROSPECTUS

Merrill Lynch & Co.

A.G. Edwards

Banc of America Securities LLC

JPMorgan

Raymond James

Petrie Parkman & Co.

KeyBanc Capital Markets

Simmons & Company International

, 2004
