Summer Infant, Inc.
Form 10-Q
November 10, 2011
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-Q

Quarterly Report Under Section 13 or 15(d) of the Securities Exchange Act of 1934

For the quarterly period ended September 30, 2011

Summer Infant, Inc.

(Exact Name of Registrant as Specified in Its Charter)

Commission file number **001-33346**

Delaware	**20-1994619**
(State or Other Jurisdiction of Incorporation or Organization)	(IRS Employer Identification No.)
1275 Park East Drive Woonsocket, RI 02895	**(401) 671-6550**
(Address of principal executive offices and Zip Code)	(Registrant s telephone number, including area code)

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 o

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 o

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

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

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

As of October 23, 2011, there were 17,427,844 shares outstanding of the registrant s Common Stock, $.0001 par value per share.

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Summer Infant, Inc. and Subsidiaries

Condensed Consolidated Balance Sheets

Note that all amounts presented in the table below are in thousands of US dollars except share and par value amounts.

	Unaudited September 30, 2011	December 31, 2010
ASSETS		
CURRENT ASSETS		
Cash and cash equivalents	$ 1,923	$ 1,138
Trade receivables, net of allowance for doubtful accounts	55,756	46,693
Inventory, net	43,798	45,853
Prepaids and other current assets	3,751	2,783
Deferred tax assets	1,269	1,269
TOTAL CURRENT ASSETS	106,497	97,736
Property and equipment, net	15,940	14,958
Goodwill	57,617	50,375
Other intangible assets, net	30,342	14,745
Other assets	21	181
TOTAL ASSETS	$ 210,417	$ 177,995
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES		
Accounts payable and accrued expenses	$ 41,462	$ 35,651
Current portion of long term debt	512	1,256
TOTAL CURRENT LIABILITIES	41,974	36,907
Long term debt, less current portion	63,259	51,963
Other liabilities	3,800	4,579
Deferred tax liabilities	8,085	8,085
TOTAL LIABILITIES	117,118	101,534
COMMITMENTS AND CONTINGENCIES		
STOCKHOLDERS EQUITY		
Common Stock $.0001 par value, issued and outstanding 17,422,835 and 15,450,227, respectively	2	1
Treasury Stock at cost (141,134 shares at September 30, 2011)	(956)	
Additional paid-in capital	70,283	56,431
Retained earnings	24,652	20,490
Accumulated other comprehensive income (loss)	(682)	(461)
TOTAL STOCKHOLDERS EQUITY	93,299	76,461
TOTAL LIABILITIES AND STOCKHOLDERS EQUITY	$ 210,417	$ 177,995

See notes to condensed consolidated financial statements

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Summer Infant, Inc. and Subsidiaries

Condensed Consolidated Statements of Income

Note that all amounts presented in the table below are in thousands of US dollars except share and per share amounts.

	Unaudited		Unaudited	
	For the three months ended		For the nine months ended	
	September 30, 2011	September 30, 2010	September 30, 2011	September 30, 2010
Net revenues	$ 63,342	$ 49,800	$ 182,803	$ 143,399
Cost of goods sold	41,347	31,854	120,895	90,022
Gross profit	21,995	17,946	61,908	53,377
Selling, general and administrative expenses	16,641	13,189	48,957	39,469
Stock-based compensation expense	335	159	837	498
Depreciation and amortization	1,562	1,414	4,646	3,897
Operating income	3,457	3,184	7,468	9,513
Interest expense, net	(774)	(454)	(2,096)	(1,135)
Income before provision for income taxes	2,683	2,730	5,372	8,378
Income tax expense	604	652	1,209	2,346
NET INCOME	$ 2,079	$ 2,078	$ 4,163	$ 6,032
Net income per share Basic	$ 0.12	$ 0.14	$ 0.25	$ 0.39
Weighted average shares outstanding basic	17,547,739	15,437,477	16,971,628	15,429,225
Net income per share Diluted	$ 0.11	$ 0.13	$ 0.23	$ 0.37
Weighted average shares outstanding - diluted	18,366,097	16,524,547	17,832,691	16,360,771

See notes to condensed consolidated financial statements.

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Summer Infant, Inc. and Subsidiaries

Condensed Consolidated Statements of Cash Flows

Note that all amounts presented in the table below are in thousands of US dollars.

	Unaudited For the nine months ended September 30, 2011		Unaudited For the nine months ended September 30, 2010	
Cash flows from operating activities:				
Net income	$	4,163	$	6,032
Adjustments to reconcile net income to net cash used in operating activities				
Depreciation and amortization		4,646		3,897
Non-cash stock option expense		837		498
Change in value of interest rate swap agreements		(209)		(332)
Changes in assets and liabilities, net of effects of acquisition:				
Increase in accounts receivable		(7,016)		(10,626)
(Increase) decrease in inventory		4,519		(14,410)
Increase in accounts payable and accrued expenses		997		6,144
(Increase) decrease in prepaids and other assets		(773)		37
Net cash provided by (used in) operating activities		7,164		(8,760)
Cash flows from investing activities:				
Acquisitions of property and equipment		(4,888)		(6,542)
Acquisition of Born Free, net of cash acquired		(13,960)		
Net cash used in investing activities		(18,848)		(6,542)
Cash flows from financing activities:				
Net borrowings on debt and other long-term liabilities		9,984		14,939
Issuance of common stock upon exercise of stock options		2,407		
Net cash provided by financing activities		12,391		14,939
Effect of exchange rate changes on cash and cash equivalents		78		694
NET INCREASE IN CASH AND CASH EQUIVALENTS		785		331
CASH AND CASH EQUIVALENTS, BEGINNING OF PERIOD		1,138		932
CASH AND CASH EQUIVALENTS, END OF PERIOD	$	1,923	$	1,263
Non cash investing activities:				
Capital lease obligation	$	390	$	286
Issuance of common stock in conjunction with acquisition of Born Free	$	9,651	$	
Cash paid for interest	$	1,943	$	1,412
Cash paid (refunded) for taxes	$	(302)	$	1,245

See notes to condensed consolidated financial statements.

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SUMMER INFANT, INC. AND SUBSIDIARIES

NOTES TO CONDENSED CONSOLIDATED FINANCIAL STATEMENTS

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES AND BASIS OF PRESENTATION

The accompanying interim condensed consolidated financial statements of Summer Infant, Inc. and its subsidiaries (the Company, or Summer) are unaudited, but in the opinion of management, reflect all adjustments, consisting of normal recurring accruals, necessary for a fair presentation of the results for the interim periods. Accordingly, they do not include all information and notes required by generally accepted accounting principles accepted in the United States of America (GAAP) for complete financial statements. The results of operations for interim periods are not necessarily indicative of results to be expected for the entire fiscal year or any other period. The balance sheet at December 31, 2010 has been derived from the audited financial statements at that date but does not include all of the information and footnotes required by GAAP for complete financial statements. These interim condensed consolidated financial statements should be read in conjunction with the Company s consolidated financial statements and notes for the year ended December 31, 2010 appearing in the Company s Annual Report on Form 10-K filed on March 22, 2011.

All significant intercompany accounts and transactions have been eliminated in the condensed consolidated financial statements. All dollar amounts in the notes to the financial statements are in thousands of US dollars except share and per share amounts.

Income Taxes

The provision for income taxes is based on the Company s estimated annualized effective tax rate for the year. The Company does not provide U.S. tax on foreign earnings considered permanently invested.

Income taxes are computed using the asset and liability method of accounting. Under the asset and liability method, a deferred tax asset or liability is recognized for estimated future tax effects attributable to temporary differences and carry forwards. The measurement of deferred income tax assets is adjusted by a valuation allowance, if necessary, to recognize future tax benefits only to the extent, based on available evidence it is more likely than not such benefits will be realized. The Company recognizes interest and penalties, if any, related to uncertain tax positions in selling, general and administrative expenses. No interest and penalties related to uncertain tax positions were accrued at September 30, 2011. The tax years 2007 through 2010 remain open to examination by the major taxing jurisdictions in which the Company operates.

Use of Estimates

The preparation of financial statements in conformity with GAAP requires our management to make estimates and assumptions that affect certain reported amounts of assets, liabilities, revenue, expenses, and related disclosures of contingent assets and liabilities. We base our estimates on historical experience, applicable laws and regulations, and various other assumptions that we believe to be reasonable under the circumstances, the results of which form the basis for making judgments about the carrying value of assets and liabilities that are not readily apparent from other sources. Accordingly, actual results could differ from those estimates.

Net Income Per Share

Basic earnings per share for the Company are computed by dividing net income by the weighted-average number of shares of common stock outstanding during the period. Diluted earnings per share includes the dilutive impact of outstanding stock options and unvested restricted share awards.

Translation of Foreign Currencies

All assets and liabilities of the Company s foreign affiliates are translated into U.S. dollars at the exchange rate in effect at the end of the quarter and the income and expense accounts of these affiliates have been translated at average rates prevailing during each respective quarter. Resulting translation adjustments are made to a separate component of stockholders equity within accumulated other comprehensive income (loss).

Revenue Recognition

The Company records revenue when all of the following occur: persuasive evidence of an arrangement exists, product delivery has occurred, the sales price to the customer is fixed or determinable, and collectability is reasonably assured. Sales are recorded net of provisions for returns and allowances, customer discounts, and other sales related discounts. The Company bases its estimates for discounts, returns and allowances on negotiated customer terms and historical experience. Customers do not have the right to return products unless the products are defective. The Company records a reduction of sales for estimated future defective product deductions based on historical experience.

Sales incentives or other consideration given by the Company to customers that are considered adjustments of the selling price of its products, such as markdowns, are reflected as reductions of revenue. Sales incentives and other consideration that represent costs incurred by the Company for assets or services received, such as the appearance of the Company s products in a customer s national circular ad, are reflected as selling and marketing expenses in the accompanying statements of income.

Goodwill and Other Intangible Assets

The Company accounts for Goodwill and Other Intangible Assets in accordance with accounting guidance that requires that goodwill and intangible assets that have indefinite useful lives and not subject to amortization be tested at least annually for impairment. We evaluate goodwill, at a minimum, on an annual basis and whenever events and changes in circumstances indicate that the carrying amount of an asset may not be recoverable. Impairment of goodwill is tested by comparing the carrying value, including goodwill, to the Company s fair value. If the carrying value exceeds the fair value, a second step is performed to measure the amount of the impairment loss, if any. Under this second step, the implied goodwill value is determined, in the same manner as the amount of goodwill recognized in a business combination, to assess the level of goodwill impairment, if any. We determine the Company s fair value using the income, or discounted cash flows, approach (DCF model) and verify the reasonableness of such fair value calculations using the market approach, which utilizes comparable companies data. The completion of the DCF model requires that we make a number of significant assumptions to produce an estimate of future cash flows. These assumptions include projections of future revenue, costs and working capital changes. In addition, we make assumptions about the estimated cost of capital and other relevant variables, as required, in estimating fair value. The projections that we use in our DCF model are updated annually and will change over time based on the historical performance and changing business conditions. The determination of whether goodwill is impaired involves a significant level of judgment in these assumptions, and changes in our business strategy, government regulations, or economic or market conditions could significantly impact these judgments. We will continue to monitor market conditions and other factors to determine if interim impairment tests are necessary in future periods. As of December 31, 2010, the estimated fair value of the Company substantially exceeded the carrying value. Management evaluates the remaining useful life of an intangible asset that is not being amortized each reporting period to determine whether events and circumstances continue to support an indefinite useful life. If an intangible asset that is not being amortized is subsequently determined to have a finite useful life, it is amortized prospectively over its estimated remaining useful life.

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Recently Issued Accounting Pronouncements

ASC Update No. 2010-06

In January 2010, the Financial Accounting Standards Board (FASB) issued Accounting Standard Codification (ASC) Update No. 2010-06, Fair Value Measurements and Disclosures (Topic 820) Improving Disclosures about Fair Value Measurements. Update No. 2010-06 requires additional disclosure within the rollforward of activity for assets and liabilities measured at fair value on a recurring basis, including transfers of assets and liabilities between Level 1 and Level 2 of the fair value hierarchy and the separate presentation of purchases, sales, issuances and settlements of assets and liabilities within Level 3 of the fair value hierarchy. In addition, Update No. 2010-06 requires enhanced disclosures of the valuation techniques and inputs used in the fair value measurements within Level 2 and Level 3. We adopted Update No. 2010-06 for our first quarter ended March 31, 2010, except for the disclosure of purchases, sales, issuances and settlements of Level 3 measurements, for which disclosures were required for our first quarter ending March 31, 2011. The adoption of this guidance had no effect on our consolidated financial position or results of operations.

ASC Update No. 2010-29

In December 2010, the FASB issued ASC Update No. 2010-29, Business Combinations (Topic 805) Disclosure of Supplementary Pro Forma Information for Business Combinations. Update No. 2010-29 clarifies paragraph 805-10-50-2(h) to require public entities that enter into business combinations that are material on an individual or aggregate basis to disclose pro forma information for such business combinations that occurred in the current reporting period, including pro forma revenue and earnings of the combined entity as though the acquisition date had been as of the beginning of the comparable prior annual reporting period only. We adopted Update No. 2010-29 for material business combinations for which the acquisition date is on or after January 1, 2011. (See Note 2)

Management does not believe that any other recently issued, but not yet effective, accounting standards if currently adopted would have a material effect on the accompanying financial statements.

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2. ACQUISITION OF BORN FREE HOLDINGS LTD.

On March 24, 2011, the Company acquired all of the capital stock of Born Free Holdings Ltd. (Born Free) pursuant to the terms and conditions of a Stock Purchase Agreement (the Purchase Agreement) by and among the Company, its wholly owned subsidiary Summer Infant (USA), Inc., Born Free and the stockholders of Born Free. The aggregate consideration paid by the Company to the Born Free stockholders at closing was $24,607 (subject to adjustment), consisting of $14,000 in cash and approximately $10,607 in shares of the Company s common stock, or 1,510,989 shares based on a price per share of $7.02 (the closing price on the date of acquisition). In addition, the Born Free stockholders may receive earn-out payments upon achievement of certain financial targets over the next twelve months up to a maximum amount of $13,000, of which up to $6,500 may be paid in shares of the Company s common stock (or 925,926 shares based on a price per share of $7.02). A portion of the shares issued at closing was, and, if achieved, a portion of the earn-out payments will be, deposited in escrow for a period of 18 months as security for any breach of the representations, warranties and covenants of Born Free and the Born Free stockholders contained in the Purchase Agreement. On September 30, 2011 the Company received $1,000 in common stock from the Born Free escrow account due to a preliminary net asset adjustment as defined in the Purchase Agreement. This is accounted for on the balance sheet through a decrease in acquired accounts receivable by $1,000, and increasing treasury stock by $956 and goodwill by $44. There may be additional adjustments in future periods.

The results of operations of Born Free are included in the results of the Company from the date of acquisition forward. Related deal expenses of approximately $1,415 were incurred during the nine months ended September 30, 2011, of which $635 relates to professional fees, and $780 relates to transition costs incurred with the ongoing integration of Born Free.

Under the purchase method of accounting, the total preliminary purchase price for Born Free has been assigned to the net tangible and intangible assets acquired and liabilities assumed, based on various preliminary estimates of their values by the Company s management. Management s estimates and assumptions are subject to change upon the finalization of the valuation and may be adjusted in accordance with FASB ASC Topic 805, Business Combinations. Valuations of all tangible and intangible assets, including customer relationships, trade name and intellectual property, have not been finalized. The Company has made a preliminary adjustment to goodwill and intangible assets, assigning $16,400 to intangible assets. In addition, the estimated fair value of the contingent earn-out has not been completed as of September 30, 2011. The assignment of the purchase price (including the estimated earn-out of up to $13,000) is expected to be completed in the fourth quarter of 2011. Accordingly, the purchase price assignment is not finalized. The acquisition will be recorded as of the closing date, reflecting the assets and liabilities of Born Free (the target), at their acquisition date fair values. Intangible assets that are identifiable are recognized separately from goodwill which is measured and recognized as the excess of the fair value of Born Free, as a whole, over the net amount of the recognized identifiable assets acquired and liabilities assumed.

Preliminary calculation of assignment consideration:

		March 24, 2011
Cash	$	14,000
Stock		9,607*
Provisional Consideration	$	23,607

Provisional assignment of purchase price among assets acquired and liabilities assumed as of March 24, 2011:

		March 24, 2011
Trade Receivables	$	2,226
Inventory		3,615
Prepaids, and other current assets		39
Property and equipment, net		1,333
Other intangible assets, net		16,400
Accounts payable		(4,970)
		18,643
Goodwill		4,964
Total assigned preliminary purchase price	$	23,607

* The stock portion of the acquisition consists of 1,369,855 shares at a price per share of $7.02.

Pro forma financial information. The pro forma financial information presented below is for informational purposes only and is not intended to represent or be indicative of the results of operations that would have been achieved if the Born Free acquisition had been completed as of the date indicated, and should not be taken as representative of the Company s future consolidated results of operations or financial condition. The unaudited pro forma financial information below summarizes the results of operations of the combined entity, as though the acquisition had occurred as of the beginning of the period presented. Preparation of the pro forma financial information required management to make certain judgments and estimates to determine the pro forma adjustments such as purchase accounting adjustments. Revenue generated from Born Free products amounted to $7,400 from March 25, 2011 to September 30, 2011 and $3,400 for the three months ended September 30, 2011.

The pro forma effect on net revenues, earnings, and earnings per share amounts for the nine months ended September 30, 2011 and 2010, assuming the Born Free transaction had closed on January 1, 2010, are as follows:

	Nine Months Ended September 30			
		2011		2010
Net Revenues	$	186,276	$	155,718
Net Income		2,989		5,318
Earnings per share	$	0.16	$	0.30

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3. DEBT

On March 24, 2011, in connection with its acquisition of Born Free, the Company and its subsidiaries entered into an amendment of its existing amended and restated credit agreement with Bank of America, N.A. and the other lenders thereunder (the Amended Loan Agreement). Among other changes, the Amended Loan Agreement provided for (i) an increase in the maximum amount of credit available from $60,000 to $80,000, (ii) a one-time right exercisable after September 30, 2011 to request an additional increase in the aggregate commitments under the Amended Loan Agreement by an amount not exceeding $20,000, (iii) a new maturity date of June 30, 2013, and (iv) revised financial covenants of the Company as described below. As additional security for the increased commitment, the Company granted the lenders a security interest in 65% of the capital stock of the newly-acquired Born Free.

The Company s ability to borrow under the Amended Loan Agreement is subject to its ongoing compliance with a number of financial and other covenants, including the following: (i) the Company and its subsidiaries maintain and earn on a consolidated basis as of the last day of each fiscal quarter trailing 12 month EBITDA (defined below) of not less than $20,000 beginning with the quarter ending on June 30, 2011 and increasing over the remaining term of the Amended Loan Agreement to $26,000 for each quarter ending on or after December 30, 2012; (ii) that the Company and its subsidiaries maintain a ratio of consolidated total funded debt to consolidated EBITDA of not greater than (a) 3.50:1.00 through September 30, 2011 and (b) 3.25:1.00 on December 31, 2011 and thereafter; and (iii) that the Company and its subsidiaries maintain a fixed charge ratio of at least 1.50:1.00.

These credit facilities bear interest at a floating rate based on a spread over LIBOR ranging from 200 basis points to 300 basis points, depending upon the ratio of the Company s total funded debt to EBITDA. As of September 30, 2011, the blended interest rate for these credit facilities was 4.15 %. In addition, these credit facilities have an unused line fee based on the unused amount of the credit facilities equal to 25 basis points. The total amount outstanding on these facilities at September 30, 2011 was $63,000.

For purpose of the Amended Loan Agreement, EBITDA means consolidated net income (excluding extraordinary gains and extraordinary losses) plus (a) the following to the extent deducted in calculating consolidated net income: (i) consolidated interest charges (ii) the provision for federal, state , local and foreign income taxes payable by the Company and its subsidiaries (iii) depreciation and amortization expense, and (iv) other non-recurring expenses of the Company and its subsidiaries reducing consolidated net income, and minus (b) the following to the extent included in calculating consolidated net income: (i) federal, state, local and foreign income tax credits of the Company and its subsidiaries and (ii) all non-cash items increasing consolidated net income.

The Amended Loan Agreement also contains customary events of default, including a cross default provision and a change of control provision. In the event of a default, all of the obligations of the Company and its subsidiaries under the Amended Loan Agreement may be declared immediately due and payable. For certain events of default relating to insolvency and receivership, all outstanding obligations become due and payable.

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4. FAIR VALUE MEASUREMENTS

The Company follows ASC 2101-06 regarding measuring fair value and related disclosures. Broadly, the framework requires fair value to be determined based on the exchange price that would be received for an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants. The standard established a three-level valuation hierarchy based upon observable and non-observable inputs.

Observable inputs reflect market data obtained from independent sources, while unobservable inputs reflect the Company s market assumptions. Preference is given to observable inputs. These two types of inputs create the following fair value hierarchy:

Level 1 Quoted prices for identical instruments in active markets.

Level 2 Quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations whose inputs are observable or whose significant value drivers are observable.

Level 3 Significant inputs to the valuation model are unobservable.

The Company maintains policies and procedures to value instruments using the best and most relevant data available. In addition, the Company utilizes risk management resources that review valuation, including independent price validation. Management concludes there has been no material change in the Company s credit risk nor that of Bank of America and therefore the valuation of the liability is reasonable.

The Company recognizes the fair value of interest rate swaps (see Note 5) using Level 2 inputs.

As of September 30, 2011 the fair value of the swaps now reflects a liability of approximately $136, which is included in other liabilities on the accompanying balance sheet. The change in fair value of the swap liability for the three and nine months ended September 30, 2011 of approximately $50 and $209 respectively is recorded in interest expense . The interest rate swaps are not accounted for as hedges.

The notional amounts under the interest rate swap agreements total $3,553, which is approximately 5.6% of the Company s total outstanding bank debt at September 30, 2011.

5. DERIVATIVE INSTRUMENTS

The Company is exposed to interest rate risk primarily through its borrowing activities. The Company s long-term debt is a variable rate instrument. The Company held one interest rate swap contract at September 30, 2011 under which the Company agreed to pay an amount equal to a specified fixed rate of interest times a notional principal amount, and to, in turn, receive an amount equal to a specified variable rate of interest times the same notional principal amount.

The Company uses derivatives to fix interest rates. As a matter of policy, the Company does not use derivatives for speculative purposes. This is a requirement in the Company s Amended Loan Agreement (described in Note 3) to mitigate interest rate risk.

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The interest rate swap contracts require payment of a fixed rate of interest and the receipt of a variable rate of interest at the LIBOR one month index rate plus 150-200 basis points on a notional amount of indebtedness.

	Rate	Notional Amount	Effective Date	Maturity Date	Mark-to-Market at September 30, 2011
Swap 1	7.06%	3,553	June 21, 2007	June 7, 2012	$ (136)
					$ (136)

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6. **COMMITMENTS AND CONTINGENCIES**

Litigation

The Company is a party to routine litigation and administrative complaints incidental to its business. Management does not believe that the resolution of any or all of such routine litigation and administrative complaints is likely to have a material adverse effect on the Company s financial condition or results of operations.

7. **STOCK OPTIONS AND RESTRICTED SHARES**

The Company has granted stock-based awards under its 2006 Performance Equity Plan (2006 Plan). Under the 2006 Plan, awards may be granted to participants in the form of Non-Qualified Stock Options, Incentive Stock Options, Restricted Stock, Deferred Stock, Stock Reload Options and other stock-based awards. Subject to the provisions of the 2006 plan, awards may be granted to employees, officers, directors, advisors and consultants who are deemed to have rendered or are able to render significant services to the Company and who are deemed to have contributed or to have the potential to contribute to the Company s success. The Company has issued both stock options and restricted shares to employees and Board members.

Share-based compensation expense for the nine months ended September 30, 2011 and 2010 was approximately $837 and $498, respectively. As of September 30, 2011, there were 1,852,300 stock options outstanding and 235,629 unvested restricted shares outstanding.

During the three months ended September 30, 2011, the Company granted 1,000 stock options. The key assumptions used in determining the valuation included:

•	Expected life	-	6 years
•	Volatility	-	55%
•	Discount rate	-	1.71%

In March 2011, the Board of Directors approved the 2010 bonus plan payout of $1,044, which consisted of the following: (i) $210 in cash bonuses; and (ii) $834 in restricted stock grants (or 113,613 shares), of which 50% had an immediate vesting and 50% vest in one year. In April 2011, 56,807 restricted shares were issued, which represents the vested portion of the total grant of 113,613 restricted shares. The non-vested portion of the restricted stock grant will be expensed from March 2011 to March 2012. Also, in June 2011, 109,515 restricted shares were granted to employees as part of a long-term incentive plan which have a four year vesting schedule, and 18,750 shares were granted to the Board of Directors as part of their compensation arrangements. All shares issued to the board of directors vested immediately.

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ITEM 2. MANAGEMENT S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Forward-Looking Statements and Factors That May Affect Results

In addition to the historical information contained in this report, this report contains forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. Forward-looking statements relate to our expectations, intentions, or strategies regarding future matters, including our ability to grow our business through developing new products, obtaining new customers, increasing our sales territory, making strategic acquisitions, integrating our acquired businesses, and our anticipated cash flow for the next 12 months. It is important to note that our actual results could differ materially from those projected in such forward-looking statements contained in this report. You are cautioned not to place undue reliance on our forward-looking statements.

All forward-looking statements included in this document are based on information available to us on the date hereof. These statements are based on current expectations that involve numerous risks and uncertainties. These risks and uncertainties include the Company s ability to integrate acquired businesses, the concentration of the Company s business with retail customers; the ability of the Company to compete in the industry; the Company s dependence on key personnel; the Company s reliance on foreign suppliers; and other risks as detailed in the Company s Annual Report on Form 10-K for the fiscal year ended December 31, 2010, and subsequent filings with the Securities and Exchange Commission. All these matters are difficult or impossible to predict accurately, many of which may be beyond our control. Although we believe that the assumptions underlying our forward-looking statements are reasonable, any of the assumptions could be inaccurate and, therefore, there can be no assurance that the forward-looking statements included in this report will prove to be accurate.

The information contained in this section has been derived from the Company s consolidated financial statements and should be read together with the consolidated financial statements and related notes included elsewhere in this filing. All dollar amounts in the following section are in thousands of US dollars except for per share amounts.

The following discussion is intended to assist in the assessment of significant changes and trends related to the results of operations and financial condition of Summer Infant, Inc. and its consolidated subsidiaries. This discussion and analysis should be read in conjunction with the Company s consolidated financial statements and notes thereto included herein.

Summary of Critical Accounting Policies and Estimates

The FASB Accounting Standards Codification (Codification) is the source of authoritative accounting principles recognized by the FASB to be applied by nongovernmental entities in the preparation of financial statements in conformity with GAAP. Rules and interpretive releases of the Securities and Exchange Commission (SEC) under authority of federal securities laws are also sources of authoritative GAAP for SEC registrants.

The Company s critical accounting policies are disclosed in the Company s Annual Report on Form 10-K and discussed in Note 1 to the unaudited consolidated financial statements included in this report. There have been no material changes to these policies during 2011. The consolidated financial statements and notes are representations of management, which is responsible for their integrity and objectivity. These accounting policies conform to accounting principles generally accepted in the United States of America (GAAP) and have been consistently applied in the preparation of the consolidated financial statements. Management of the Company makes certain estimates and assumptions that affect the reported amounts of assets and liabilities and the reported amounts of revenues and expenses. Some of these policies include significant estimates made by management using information available at the time the estimates were made. However, these estimates could change materially if different information or assumptions were used.

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Overview

We are a designer, marketer, and distributor of branded juvenile health, safety and wellness products which are sold principally to large North American and UK retailers. We currently market proprietary products in various product categories including nursery audio/video monitors, safety gates, durable bath products, bed rails, infant feeding, furniture, baby gear, infant thermometers and related health and safety products, booster and potty seats and bouncers. Our business has grown organically in all our markets. We derive revenues from the sale of these products. Our revenue is driven by our ability to design and market desirable products, identify business opportunities and secure new and renew existing distribution channels. Our income from operations is derived from our ability to generate revenue and collect cash in excess of labor and other cost of providing our product and selling, general and administrative costs.

Our strategy is to grow our sales through a variety of methods, including:

- increasing product penetration (more products at each store);
- increasing store penetration (more stores within each retail customer);
- introducing new products (at existing and new customers);
- obtaining new mass merchant retail customers;
- developing new distribution channels (food and drug chains, price clubs, home centers, and web-based retailers);
- entering new geographies (international expansion);
- entering new product categories; and
- making strategic acquisitions.

Historically we have has been able to grow our annual revenues significantly through a combination of all of the above factors. Each year we have been able to expand the number of products in our main distribution channel, and the number of mass merchant retailers, and have also added new customers each year.

For 2011 and beyond, our growth strategy will be to continue to develop and sell new products to our existing customer base, sell new and existing products to new customers and expand in the United Kingdom and in other geographic regions (such as Japan, Mexico and Australia).

Acquisition of Born Free

In the past we have pursued, and we expect to continue to pursue, potential strategic acquisitions to obtain new innovative products, new product categories, new retail customers or new sales territories. In March 2011, we acquired all of the capital stock of Born Free Holdings Ltd. (Born Free) pursuant to the terms and conditions of a Stock Purchase Agreement by and among us, our wholly owned subsidiary Summer Infant (USA), Inc., Born Free and the stockholders of Born Free. Born Free is a manufacturer of baby bottles, drinking cups, and other feeding related items. The aggregate consideration paid to the Born Free stockholders at closing was $24,600, consisting of $14,000 in cash and approximately $10,600 in shares our common stock. In addition, the Born Free stockholders may receive earn-out payments upon achievement of certain financial targets over the next twelve months up to a maximum amount of $13,000, of which up to $6,500 may be paid in shares of our common stock.

During the second quarter the Born Free operations in the United States, Canada and United Kingdom were all merged into the Company s existing operations in those same countries. As part of the integration, we incurred costs of approximately $780 related to severance, lease termination and other costs, which are reflected in selling, general and administrative expenses in our financial statements. We are now handling all product development, sales, operations and finance for Born Free in a centralized manner. In addition, a recent, key initiative is the development of new products under the Born Free brand in a variety of feeding categories. We believe these categories have potential for future sales growth, and we have developed a team to drive these efforts.

On September 30, 2011 the Company received $1,000 in common stock from the Born Free escrow account due to a preliminary net asset adjustment as defined in the Purchase Agreement. This is accounted for on the balance sheet through an increase in acquired accrued expenses by $1,000, and increasing treasury stock by $956 and goodwill by $44. There could be additional adjustments in future periods.

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As we continue to grow through internal initiatives and any additional future acquisitions, we will incur additional expenses. Two of the key areas in which such increased expenses will likely occur are sales and product development. To grow sales, we will likely hire additional sales personnel to service new geographic territories, focus existing resources on specific parts of the United States market and retain product line specialists to drive sales of new and existing products in specific areas in which we believe we can readily increase sales. Product development expenses are expected to increase as we develop new products in existing and new categories. As a result of our acquisition strategy, we will face various challenges such as the integration of the acquired companies product lines, employees, marketing requirements and information systems. Ongoing infrastructure investment also may be required to support realized growth, including expenditures with respect to upgraded and expanded information systems and enhancing the Company s management team.

Revenues

Our revenues are primarily derived from the sale of branded juvenile health, safety and wellness products and are recognized upon transfer of title of product to our customers. Our products are marketed through several distribution channels including chain retailers, specialty retailers, on-line retailers and direct to consumers.

Over 90% of our sales are currently made to customers in North America, with remaining sales primarily made to customers in the United Kingdom. Sales are made utilizing standard credit terms of 30 to 60 days. We generally accept returns only for defective merchandise.

There are not significant variations in seasonal demand for our products. Sales to its retail customers are generally higher in the time frame when retailers take initial shipments of new products; these orders usually incorporate enough product to fill each store plus additional amounts to be kept at the customer s distribution center. The timing of these initial shipments varies by customer depending on when they finalize store layouts for the upcoming year, and whether there are any mid-year product introductions.

Cost of goods sold

Our products are manufactured by third parties, with approximately 90% of the dollar value of products being manufactured in Asia and the majority of the balance being manufactured in the United States. Cost of goods sold primarily represents purchases of finished products from these third party manufacturers. The remainder of our cost of goods sold includes duties on certain imported items, freight-in from suppliers and miscellaneous charges from contract manufacturers. Substantially all of our purchases are made in US dollars, therefore, most of this activity is not subject to currency fluctuations. If our suppliers experience increased raw materials, labor or other costs and pass along such cost increases through higher prices for finished goods, our costs of sales would increase, and to the extent we are unable to pass such price increases along to our customers, our gross margins would decrease.

Selling, general and administrative expenses

Selling, general and administrative expenses primarily consist of payroll, insurance, professional fees, royalties, freight out to customers, product development costs, advertising and marketing expenses (including co-op advertising allowances as negotiated with certain customers) and sales commissions. Several of these items fluctuate with sales, some based on sales to particular customers and others based on sales of particular products.

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Results of Operations

Summer Infant and Subsidiaries

Condensed Consolidated Statements of Income

For the Three and Nine Months Ending September 30, 2011 and 2010

(Unaudited)

	Unaudited		Unaudited	
	For the three months ended		For the nine months ended	
	September 30, 2011	September 30, 2010	September 30, 2011	September 30, 2010
Net revenues	$ 63,342	$ 49,800	$ 182,803	$ 143,399
Cost of goods sold	41,347	31,854	120,895	90,022
Gross profit	21,995	17,946	61,908	53,377
Selling, general and administrative expenses	16,641	13,189	48,957	39,469
Stock-based compensation expense	335	159	837	498
Depreciation and amortization	1,562	1,414	4,646	3,897
Net operating income	3,457	3,184	7,468	9,513
Interest expense, net	(774)	(454)	(2,096)	(1,135)
Income before provision for income taxes	2,683	2,730	5,372	8,378
Income tax expense	604	652	1,209	2,346
NET INCOME	$ 2,079	$ 2,078	$ 4,163	$ 6,032

We may in the future enter into these and other types of hedging arrangements to reduce our exposure to fluctuations in the market prices of oil and natural gas. Hedging transactions expose us risk of financial loss in some circumstances, including if production is less than expected, the other party to the contract defaults on its obligations or there is a change in the expected differential between the underlying price in the hedging agreement and actual prices received. Hedging transactions may limit the benefit we would have otherwise received from increases in the price fo oil and natural gas. Furthermore, if we do not engage in hedging transactions, then we may be mor adversely affected by declines in oil and natural gas prices than our competitors who engage in hedging transactions. Additionally, hedging transactions may expose us to cash margin requiremen

Risks Relating to this Offering and Our Common Stock

We can provide no assurance that we will successfully complete our concurrent offering of 7,500,000 shares of our common stock or that we will be able to reduce our outstanding indebtedness with the proceeds of the concurrent offering.

We have entered into a purchase agreement with respect to a primary offering of 7,500,000 shares our common stock. Based on the public offering price of $29.02 per share, we will receive net proceeds of approximately $208.4 million after deducting the underwriting discount and estimated offering expenses. We expect to use all of the net proceeds from this concurrent offering to repay debt outstanding under Whiting Oil and Gas Corporation s credit agreement that we incurred in connection with the acquisitions described under Prospectus Summary Recent Acquisitions and Business and Properties Recent Acquisitions. If we are unable to complete our offering of prim shares, we will be unable to reduce our indebtedness with the anticipated proceeds therefrom. The offering of our shares of common stock by Resources being made by this prospectus is not conting on the successful completion of our concurrent primary offering.

Our stock price may be volatile.

The market price of our common stock could be subject to significant fluctuations, and may declin The following factors could affect our stock price:

our operating and financial performance and prospects,

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- quarterly variations in the rate of growth of our financial indicators, such as net income per share, net income and revenues,
- changes in revenue or earnings estimates or publication of research reports by analysts,
- speculation in the press or investment community,
- general market conditions, including fluctuations in commodity prices, and
- domestic and international economic, legal and regulatory factors unrelated to our performance.

The stock markets in general have experienced extreme volatility that has often been unrelated to t operating performance of particular companies. These broad market fluctuations may adversely aff the trading price of our common stock.

We have no plans to pay dividends on our common stock. You may not receive funds without selling your shares.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. W currently intend to retain future earnings, if any, to finance the expansion of our business. Our futu dividend policy is within the discretion of our board of directors and will depend upon various factors, including our business, financial condition, results of operations, capital requirements and investment opportunities. In addition, the agreements governing our indebtedness prohibit us from paying dividends.

Provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stoc

The existence of some provisions in our organizational documents and under Delaware law could delay or prevent a change in control of our company, which could adversely affect the price of our common stock. The provisions in our certificate of incorporation and by-laws that could delay or prevent an unsolicited change in control of our company include a staggered board of directors, bo authority to issue preferred stock, advance notice provisions for director nominations or business to be considered at a stockholder meeting and supermajority voting requirements. In addition, Delawa law imposes some restrictions on mergers and other business combinations between us and any holder of 15% or more of our outstanding common stock. See Description of Capital Stock Prefe Stock and Description of Capital Stock Delaware Anti-Takeover Law and Charter and By-law Provisions.

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SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus contains statements that we believe to be forward looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. All statements other than historic facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward looking statements. When used in this prospectus, words such as we expect, intend, plan, estimate, anticipate, believe o negative thereof or variations thereon or similar terminology are generally intended to identify forward looking statements. Such forward looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. Some, but not all, of the risks and uncertainties include: declines in oil or natural gas prices; our level of success in exploitation, exploration, development and production activities; our ability to obtain external capital to finance acquisitions; our ability to identify and complete acquisitions and to successfully integrate acquired businesses, including our ability to realize cost savings from the acquisitions we completed in 2004; unforeseen underperformance of or liabilities associated with acquired properties; inaccuracies of our reserve estimates or our assumptions underlying them; failure of our properties to yield oil or natural gas in commercially viable quantities; uninsured or underinsured losses resulting from our oil and natural gas operations; our inability to access oil and natural gas markets due to market conditions or operational impediments the impact and costs of compliance with laws and regulations governing our oil and natural gas operations; risks related to our level of indebtedness; our ability to replace our oil and natural gas reserves; any loss of our senior management or technical personnel; competition in the oil and natu gas industry; risks arising out of our hedging transactions; and other risks described under the capti Risk Factors . We assume no obligation, and disclaim any duty, to update the forward looking statements in this prospectus.

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USE OF PROCEEDS

We will not receive any of the net proceeds from the sale of common stock by the selling stockholder. We can provide you no assurance that our concurrent offering of 7,500,000 primary shares will be completed or that we will receive any of the anticipated proceeds from that offering.

CAPITALIZATION

The following table sets forth our capitalization as of September 30, 2004 on an actual basis. This table also reflects our capitalization as of such date as adjusted to reflect the proposed sale of 7,500,000 primary shares of our common stock in a concurrent offering at the public offering price $29.02 per share, after deducting the underwriting discount and estimated offering expenses, and th application of the net proceeds from the concurrent offering to reduce the indebtedness we incurred in connection with our recent Permian Basin acquisition. You should read this table in conjunction with our financial statements and the notes to those financial statements included elsewhere in this prospectus. We can provide no assurance that our concurrent offering of primary shares will be completed or that we will receive any of the anticipated proceeds from that offering. If we do not complete our primary offering, then our indebtedness will not be reduced by the amount of such expected proceeds.

	September 30, 2004	
	Actual	As Adjust
	(dollars in thousands)	
Cash and cash equivalents	$ 17,361	$ 17,36
Short-term debt	$ 50,000	$
Long-term debt:		
Whiting Oil and Gas Corporation credit agreement	385,000	226,63
Note payable to Alliant Energy Corporation	3,130	3,13
Senior subordinated notes(1)	150,697	150,69
Total debt	588,827	380,43
Stockholders equity:		
Common stock: $0.001 par value, 75,000,000 shares authorized, 21,100,347 shares issued and outstanding	21	2
Preferred Stock: $0.001 par value, 5,000,000 shares authorized, no shares issued or outstanding		
Additional paid-in capital	216,120	424,48
Deferred compensation	(2,035)	(2,03
Accumulated other comprehensive loss	(6,050)	(6,05
Retained earnings	126,841	126,84
Total stockholders equity	$ 334,897	$ 543,26
Total capitalization	$ 923,724	$ 923,72

(1) Represents $150.0 million aggregate principal amount of 7 $^{1}/4$% senior subordinated notes due 2012.

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PRICE RANGE OF COMMON STOCK AND DIVIDENDS

Our common stock has been traded on the New York Stock Exchange under the symbol WLL s
our initial public offering on November 20, 2003. The following table shows the high and low sale
prices for our common stock for the periods presented.

	High	Lo
Fiscal Year Ended December 31, 2003		
Fourth Quarter (from November 20, 2003 through December 31, 2003)	$ 18.54	$ 16
Fiscal Year Ended December 31, 2004		
First Quarter (Ended March 31, 2004)	$ 23.94	$ 18
Second Quarter (Ended June 30, 2004)	$ 27.59	$ 21
Third Quarter (Ended September 30, 2004)	$ 31.20	$ 21
Fourth Quarter (Through November 16, 2004)	$ 34.22	$ 27

On November 16, 2004, the last sale price of our common stock as reported on the New York Stoc
Exchange was $29.02.

As of October 14, 2004, there were 996 stockholders of record and approximately 16,000 beneficia
owners of our common stock.

We have not paid any dividends since we were incorporated in July 2003. We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy i within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, the agreements governing our indebtedness prohibit us from paying dividends.

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UNAUDITED PRO FORMA FINANCIAL STATEMENTS

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, which we refer to a 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 $345.0 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 2 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisia 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 the September 30, 2004 balance sheet of Whit Petroleum Corporation included elsewhere in this prospectus. The unaudited pro forma statement o operations for the nine months ended September 30, 2004 and for the year ended December 31, 20 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, genera administrative expenses, income taxes or interest expense, as described in Notes 2 and 3, these cos 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 agreement to $750 million with a $480 million borrowing base. After the closing of this acquisition, we had $400 million of outstanding borrowin under the facility.

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

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

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UNAUDITED CONDENSED PRO FORMA STATEMENT OF OPERATIONS FOR

THE NINE MONTHS ENDED SEPTEMBER 30, 2004 (in millions, except per share data)

	Whiting Petroleum Corporation Nine Months Ended September 30, 2004	Permian Basin Acquisition Properties Six Months Ended June 30, 2004	Pro Forma Adjustments (Note 2)	Pro Form Combine September 2004
REVENUES				
Oil and gas sales	$ 166.4	$ 39.1	$ 19.3	$ 224
Loss on oil and gas hedging activities	(3.6)			(3
Gain on sale of marketable securities	4.7			4
Gain on sale of oil and gas properties	1.0			1
Interest income and other	0.2			0
Total revenues	168.7	39.1	19.3	227
COSTS AND EXPENSES:				
Lease operating	34.6	8.3	2.6	45
Production taxes	10.2	2.3	1.1	13
Depreciation, depletion and amortization	34.5		14.0	48
Exploration and impairment	4.7			4
General and administrative	14.2		2.9	17
Interest expense	9.6		8.3	17
Total costs and expenses	$ 107.8	10.6	28.9	147
INCOME BEFORE INCOME TAXES	60.9	$ 28.5	(9.6)	79
INCOME TAX EXPENSE:				
Current	(0.4)			(0
Deferred	(23.1)		(7.3)	(30
Total income tax expenses	(23.5)		(7.3)	(30
NET INCOME	$ 37.4		$ (16.9)	$ 49
NET INCOME PER COMMON SHARE, BASIC AND	$ 1.93			$ 2.

DILUTED		
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	19,341	19,34
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	19,370	19,37

See accompanying notes to pro forma statements of operations.

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UNAUDITED CONDENSED PRO FORMA STATEMENT OF OPERATIONS FOR

THE YEAR ENDED DECEMBER 31, 2003 (in millions, except per share data)

	Whiting Petroleum Corporation Year Ended December 31, 2003	Permian Basin Acquisition Properties Year Ended December 31, 2003	Pro Forma Adjustments (Note 2)	Pro Form Combine December 2003
REVENUES				
Oil and gas sales	$ 175.8	$ 91.2	$	$ 267
Loss on oil and gas hedging activities	(8.7)			(8
Interest income and other	0.3			0
Total revenues	167.4	91.2		258
COSTS AND EXPENSES:				
Lease operating	43.2	14.0		57
Production taxes	10.7	5.2		15
Depreciation, depletion and amortization	41.3		25.9	67
Exploration	3.2			3
General and administrative	12.8		4.7	17
Phantom equity plan	10.9			10
Interest expense	9.2		10.5	19
Total costs and expenses	131.3	19.2	41.1	191
INCOME BEFORE INCOME TAXES AND CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	36.1	$ 72.0	(41.1)	67
INCOME TAX EXPENSE:				
Current	(2.4)			(2
Deferred	(11.5)		(11.9)	(23
Total income tax expense	(13.9)		(11.9)	(25
INCOME FROM CONTINUING OPERATIONS	22.2		(53.0)	41
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	(3.9)			(3
NET INCOME	$ 18.3		$ (53.0)	$ 37
Earnings per share from continuing operations, basic and	$ 1.18			$ 2.

diluted		
Cumulative change in accounting principle	(0.20)	(0.2
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 0.98	$ 2.0
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC AND DILUTED	18,750	18,75

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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 & Ga 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 2 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisian 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, genera administrative expenses, income taxes or interest expense, as described in Notes 2 and 3, these cos 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 result of operations would have been if this acquisition had occurred on January 1, 2003. These unaudite pro forma financial statements should be read in conjunction with our historical financial statemen 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 o common shares outstanding and other dilutive securities. The only securities considered dilutive ar 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 t closing date of September 23, 2004.

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

General and Administrative To record expenses associated with anticipated increases in personne 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 i 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 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 a 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 presentatio 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 resu 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 U acquisition that closed on September 30, 2004, but our balance sheet information as of September 2004 does include the effect of such acquisition.

	Nine Months Ended September 30,		Year Ended December 31,				
	2004	2003	2003	2002	2001	2000	199
	(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
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
Gain on sale of marketable securities	4.7						
Interest income and other	0.2	0.2	0.3		0.2	0.1	0
Total revenues	$ 168.7	$ 124.8	$ 167.4	$ 120.5	$ 139.4	$ 111.0	$ 71
Costs and expenses:							
Lease operating	$ 34.6	$ 32.1	$ 43.2	$ 32.9	$ 29.8	$ 23.8	$ 20
Production taxes	10.2	8.1	10.7	7.4	6.5	5.4	3
Depreciation, depletion and amortization[(1)]	34.5	30.7	41.3	43.6	26.9	21.5	19
Exploration and impairment	4.7	1.0	3.2	1.8	0.8	1.1	5
Phantom equity plan[(2)]			10.9				
General and administrative	14.2	9.5	12.8	12.0	10.9	6.3	4

Interest expense	9.6	7.1	9.2	10.9	10.2	7.5	5
Total costs and expenses	$ 107.8	$ 88.5	$ 131.3	$ 108.6	$ 85.1	$ 65.6	$ 58
Income before income taxes and cumulative change in accounting principle	$ 60.9	$ 36.3	$ 36.1	$ 11.9	$ 54.3	$ 45.4	$ 12
Income tax expense(3)	(23.5)	(13.8)	(13.9)	(4.2)	(13.1)	(11.7)	(1
Income from continuing operations	37.4	22.5	22.2	7.7	41.2	33.7	10
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
Net income per common share from continuing operations, basic and diluted	$ 1.93	$ 1.20	$ 1.18	$ 0.41	$ 2.20	$ 1.80	$ 0.
Net income per common share, basic and diluted	$ 1.93	$ 0.99	$ 0.98	$ 0.41	$ 2.20	$ 1.80	$ 0.
Other Financial Information:							
Net cash provided by operating activities	$ 96.9	$ 75.0	$ 96.4	$ 62.6	$ 62.3	$ 42.3	$ 38
Capital expenditures(5)	$ 498.1	$ 33.1	$ 52.0	$ 165.4	$ 99.6	$ 139.1	$ 34
EBITDA(6)	$ 105.0	$ 70.2	$ 82.6	$ 66.4	$ 91.4	$ 74.4	$ 37

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	As of September 30,		As of December 31,				
	2004	2003	2003	2002	2001	2000	199
	(dollars in millions)						
Balance Sheet Information:							
Total assets	$ 1,054.6	$ 502.5	$ 536.3	$ 448.5	$ 319.8	$ 256.4	$ 14
Long-term debt[7]	$ 538.8	$ 185.0	$ 188.0	$ 265.5	$ 163.6	$ 139.7	$ 7
Stockholder s equity	$ 334.9	$ 224.9	$ 259.6	$ 122.8	$ 111.5	$ 70.0	$ 3

(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 milli 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 200 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 equ 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 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 ta 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-i capital as opposed to a reduction in income tax expense.

(4) In 2003, we adopted Statement of Financial Accounting Standards No. 143, Accounting for A 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 expenditure 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 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 Ended September 30,		Year Ended December 31,				
	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 statemen included elsewhere in this prospectus. The following discussion includes forward-looking statemen 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 activiti 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 acquisitio 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 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, w 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 nev 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 additi 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 opini 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 20
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 o
substantial recent acquisition activity, our discussion and analysis of our historical financial condit
and results of operations for the periods discussed below may not necessarily be comparable with o
applicable to our future results of operations. Our historical results include the results from our rec
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
2004 does include the effect of such acquisition. See Unaudited Pro Forma Financial Statements
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 contro
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 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 produc 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 3		
	2004	2003	2003	2002	20
Net production:					
Natural gas (Bcf)	17.1	16.1	21.6	21.4	1
Oil (MMbbls)	2.2	1.9	2.6	2.3	
Net sales (in millions):					
Natural gas[(1)]	$ 90.6	$ 80.1	$ 104.4	$ 68.6	$ 7
Oil[(1)]	$ 75.8	$ 53.5	$ 71.3	$ 54.1	$ 4
Average sales price:					
Natural gas (per Mcf)[(1)]	$ 5.30	$ 4.98	$ 4.78	$ 3.21	$ 3
Oil (per Bbl)[(1)]	$ 35.13	$ 27.71	$ 27.50	$ 23.35	$ 23
Costs and expenses (per Mcfe):					
Lease operating expenses	$ 1.15	$ 1.16	$ 1.16	$ 0.93	$ 0
Production taxes	$ 0.34	$ 0.29	$ 0.29	$ 0.21	$ 0
Depreciation, depletion and amortization expense	$ 1.15	$ 1.11	$ 1.11	$ 1.24	$ 1
General and administrative expenses, net of reimbursements	$ 0.47	$ 0.34	$ 0.34	$ 0.34	$ 0

(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 ar 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 ga 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 durir the first nine months of 2004 incurring no hedging loss or gain, and 42% of our natural gas volume during the same period of 2003 incurring a hedging loss of $8.0 million. We hedged 42% of our oi 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 Quantitative Disclosures About Market Risk for a list of our outstanding oil and natural gas hedg 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 g 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 gro proceeds of $1.0 million.

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Lease Operating Expenses. Our lease operating expenses per Mcfe decreased from $1.16 during th 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 sale

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 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	Nine Months Ended September 30, 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 full 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 n
months of 2004, consistent with the yearly estimated effective tax rate for 2003. Prior to our IPO, v
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
this step-up in tax basis and the net operating loss generated during the post-IPO stub period in 200
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
SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies t
legal obligations

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associated with the retirement of long-lived assets and requires us to recognize the fair value of ass retirement obligations in our financial statements by capitalizing that cost as a part of the cost of th related asset. This statement applies directly to plug and abandonment liabilities associated with ou 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 retirem 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 $3 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 volum 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 a 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 millio 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 natura 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 fron $23.35 in 2002 to $27.50 in 2003. The volume increase for oil and natural gas primarily resulted fr 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 durir 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 hedgin 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 gai 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 o operations to be located in Michigan and North Dakota, where weather conditions, sulfur content a 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 purcha 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 dr hole in 2002.

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General and Administrative Expenses. General and administrative expenses increased 6.9%, or $0. 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 20 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 no terminated.

Interest Expense. Interest expense decreased $1.7 million to $9.2 million in 2003 compared to $10 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 th future when they are utilized by Alliant Energy. Under generally accepted accounting principles, th 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, Secti 29 credits will not be available in periods subsequent to 2002.

Cumulative Change in Accounting Principle. Effective January 1, 2003, we adopted the provisions SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies 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 pa 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 highe 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 $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 natura gas price from $3.82 Mcf in 2001 to $3.21 Mcf in 2002, partially offset by an increase in natural ga 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 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.

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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 hedg 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 gain of $1.0 million, while in 2001, we divested several properties, realizing total sales gains of $1 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 operations to be located in Michigan and North Dakota, where weather conditions, sulfur content a 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 averag than other areas where we own significant producing properties.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense in 20 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 depreciation, depletion and amortization expense. Without this credit, our depreciation, depletion a amortization expense charge for 2001 would have been $35.9 million. The increase to $43.6 millio of depreciation, depletion and amortization expense in 2002 was a result of increasing sales volum 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 wit $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 process of our geophysical library.

General and Administrative Expenses. General and administrative expenses increased 9.5% or $1. million from $10.9 million in 2001 to $12.0 million in 2002. This increase was related to increases compensation expense associated with increased personnel required to administer our growth and t general cost inflation.

Interest Expense. Interest expense increased $0.7 million to $10.9 million in 2002 compared to $10 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 200 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, 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 ta 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 primar 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 decreas 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 an 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 1 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 o 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 budgete capital expenditures for the further development of our property base are $80.0 million during 200 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 th $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 t seek property acquisition opportunities that complement our existing core property base. We expec to fund the remainder of our 2004 development expenditures from internally generated cash flow a 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 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 ma 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 amende 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 agreeme The borrowing base under the credit agreement is determined in the discretion of the lenders based the collateral value of our proved reserves that have been mortgaged to the lenders and is subject t regular redetermination on May 1 and November 1 of each year as well as special redetermination 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 natu gas producing properties in the Permian Basin. On September 30, 2004, we borrowed an additiona $35.0 million to fund an additional acquisition.

The credit agreement provides for interest only payments until September 23, 2008, when the entir 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 th
principal balance to $385.0 million. Whiting Oil and Gas Corporation may, throughout the four yea
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 th
LIBOR rate plus a margin where the margin varies from 1.00% to 1.75% depending on the utilizat
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
component of interest expense.

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The credit agreement contains restrictive covenants that may limit our ability to, among other thing 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 EBITDA (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 the form of costless collars or fixed price swaps, with a minimum floor price of $35 per barrel of o or $4.50 per MMbtu. After December 31, 2005, the credit agreement will not require us to hedge a 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 us so that we may pay interest on our senior subordinated notes, it does not allow our subsidiaries t make payments to us to pay principal on the senior subordinated notes. We were in compliance wit our covenants under the credit agreement as of September 30, 2004. The credit agreement is secure 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 n 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 discou 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. Th 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 promissor 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 th 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 thi 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 u had the increase in basis not occurred. In 2014, we will be obligated to pay Alliant Energy the pres value of the remaining tax benefits assuming all such tax benefits will be realized in future years. T initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferr 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, aggregat 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 note 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 month of 2004, then $5.4 million annually through the term of the notes.

	Payments due by period				
		Less than			More t
Contractual Obligations	Total	1 year	1-3 years	3-5 years	5 yea
Long-Term Debt	$ 588.8	$ 50.0	$ 3.1	$ 385.0	$ 15
Operating Lease	5.7	0.9	1.8	1.8	
Tax Separation and Indemnification Agreement with Alliant Energy[1]	30.6		4.2	3.1	2
Total	$ 625.1	$ 50.9	$ 9.1	$ 389.9	$ 17

[1] Amounts shown are estimates based on estimated future income tax benefits from the increase tax basis described under Tax Separation and Indemnification Agreement with Alliant Energ above.

Off-Balance Sheet Arrangements. As part of a 2002 purchase transaction, we agreed to share with t seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barr 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 exces 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 combin initiated after June 30, 2001 and eliminates the pooling-of-interests method. In July 2001, the FAS issued SFAS No. 142, Goodwill and Other Intangible Assets, which discontinues the practice o 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 tha 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 mine 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 SF 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 th 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 consiste 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 obligatio in our financial statements by capitalizing that cost as a part of the cost of the related asset. In rega 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 the properties. The discounted liability is based on historical abandonment costs in specific areas a is accreted at the end of each accounting period through charges to accretion expense. The liability discounted using a credit-adjusted risk-free rate of approximately 7%. If the obligation is settled fo 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 charg 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 fo Guarantees, Including Indirect Guarantees of Indebtedness of Others was issued in November 20 by the FASB. FIN 45 requires a guarantor to recognize a liability for the fair value of the obligatio 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 guarante 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 o our financial statements.

Critical Accounting Policies and Estimates

Our discussion of financial condition and results of operation is based upon the information reporte 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 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 ar 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 amour of production delivered to purchasers and the price we will receive. Variances between our estimat revenue and actual payment are recorded in the month the payment is received; however, differenc have been insignificant.

Hedging. Our crude oil and natural gas hedges are designed to be treated as cash flow hedges unde Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments an Hedging Activity. This policy is significant since it impacts the timing of revenue recognition. Ur 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 f 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 success 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 Sta 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 certain 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 estimat 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 Ryde 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 staf 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 futur net undiscounted cash flows on a field-by-field basis using escalated prices to the net recorded boo cost at the end of each period. If the net capitalized cost exceeds net future cash flows, the cost of t property is written down to fair value, which is determined using net discounted future cash flov 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 a services of oil field companies, suppliers and others associated with the industry put extreme press on the economic stability and

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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 price 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 evalua other forms of derivative instruments as well. Our derivative contracts have historically qualified f 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 th 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 our production, but will continue to limit our hedging to a maximum of 75% of our forecasted PDI production. We also seek to diversify our hedge position with various counterparties where we hav 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/Ceil
Natural Gas	10/2004 to 12/2004	400,000	4.50/9
Natural Gas	10/2004 to 12/2004	400,000	4.50/12
Natural Gas	10/2004 to 12/2004	650,000	4.50/8

Natural Gas	01/2005 to 03/2005	400,000	5.00/12
Natural Gas	01/2005 to 03/2005	500,000	5.00/11
Natural Gas	01/2005 to 03/2005	600,000	5.00/10
Natural Gas	04/2005 to 06/2005	1,500,000	4.50/8
Natural Gas	07/2005 to 09/2005	1,500,000	4.50/8
Natural Gas	10/2005 to 12/2005	1,500,000	4.50/10
Crude Oil	10/2004 to 12/2004	50,000	28.00/46
Crude Oil	10/2004 to 12/2004	50,000	30.00/48
Crude Oil	10/2004 to 12/2004	44,000	35.00/51
Crude Oil	10/2004 to 12/2004	120,000	37.00/49
Crude Oil	10/2004 to 12/2004	50,000	37.00/54
Crude Oil	01/2005 to 03/2005	50,000	35.00/50
Crude Oil	01/2005 to 03/2005	94,000	35.00/49
Crude Oil	01/2005 to 03/2005	120,000	37.00/46
Crude Oil	01/2005 to 03/2005	80,000	37.00/50
Crude Oil	04/2005 to 06/2005	250,000	37.00/46
Crude Oil	07/2005 to 09/2005	250,000	35.00/47
Crude Oil	10/2005 to 12/2005	125,000	35.00/60
Crude Oil	10/2005 to 12/2005	125,000	35.00/65

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The collared hedges shown above have the effect of providing a protective floor while allowing us share in upward pricing movements. Consequently, while these hedges are designed to decrease ou exposure to price decreases, they also have the effect of limiting the benefit of price increases beyo 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 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 th natural gas we produce in Michigan. All of those contracts have built-in pricing escalators of 4% p year. Our outstanding fixed price marketing contracts at October 28, 2004 are summarized below:

Commodity	Period	Monthly Volume (MMBtu)	2004 P Per MM
Natural Gas	01/2002 to 12/2011	51,000	$ 4
Natural Gas	01/2002 to 12/2012	60,000	$ 3

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%/6
January March 2005	1,611,000/344,000	62%/7
April June 2005	1,611,000/250,000	62%/5
July September 2005	1,611,000/250,000	62%/5
October December 2005	1,611,000/250,000	62%/5
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 ma value but do not impact results of operations or cash flows. Conversely, for the portion of the credi facility that has a floating interest rate, interest rate changes will not affect the fair market value bu 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, 200 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 duri 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 millio of our 7 1/4% Senior Subordinated Notes due 2012. Because this swap meets the conditions to qual for the short cut method of assessing effectiveness under the provisions of Statement of Financi Accounting Standards No. 133, the change in fair value of the debt is assumed to equal the change the fair value of the interest rate swap. As such, there is no ineffectiveness assumed to exist betwee 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 pa 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 si 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. A 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 activiti 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 w 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 tha complement our existing core properties. We believe that our exploitation and acquisition expertis and our drilling inventory, together with our operating experience and efficient cost structure, prov 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. 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 o approximately 13.4 years.

The following table summarizes our estimated proved reserves and pre-tax PV10% value within ou 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 2 Averag Daily Producti
Core Area	Oil (MMbbl)	Natural Gas (Bcf)	Total (Bcfe)	% Natural Gas	Pre-Tax PV10% Value (In millions)	(MMcfe
Permian Basin	37.7	47.9	274.2	17.5%	$ 731.5	4
Rocky Mountains[1]	43.3	76.3	336.4	22.7%	$ 716.1	6
Gulf Coast	3.3	96.2	115.8	83.0%	$ 324.2	3
Michigan	1.9	87.8	99.1	88.6%	$ 219.1	2
Mid-Continent	2.0	15.7	27.9	56.4%	$ 61.8	
California	0.0	14.0	14.0	100.0%	$ 35.2	
Total	88.2	337.9	867.3	39.0%	$ 2,087.9	17

(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	Pre-Tax PV 10% Value (In millions)[6]	October Average Produc (MMc
Permian Basin[1] Properties	$ 345.0	34.2	44.6	250.0	17.8%	59%	$ 673.6	
Equity Oil Company[2]	$ 72.6	10.2	42.1	103.6	40.6%	69%	$ 217.6	
Colorado/ Wyoming[3]	$ 44.2	3.4	19.4	40.1	48.4%	82%	$ 76.6	
Wyoming/Utah[4]	$ 35.0	3.6	11.1	32.6	34.1%	92%	$ 64.5	
Louisiana/Texas[5]	$ 19.3	0.5	10.7	13.9	76.9%	57%	$ 39.5	
Subtotal Acquisitions	$ 516.1	52.0	127.9	440.1	29.1%	66%	$ 1,071.8	
Whiting Historical		36.2	210.0	427.2	49.2%	78%	$ 1,016.1	
Total		88.2	337.9	867.3	39.0%	72%	$ 2,087.9	

(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 barre 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 Te and Southeast New Mexico, including interests in key fields such as Parkway Field in Eddy Count 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 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 MMcf 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 approximatel 300 operated producing wells in our Permian Basin core area with this acquisition.

Attractive Operating Cost Profile. The acquired Permian Basin properties operating performance 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 o historical lease

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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 th impact of this acquisition, our Permian Basin region is now nearly as large as our Rocky Mountain 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 expert 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 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 producti Wells are being drilled to convert the five spot flood pattern to a nine spot pattern. We have identif 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 o the Clearfork Formation, the Would Have and the Dillard Limestones. A waterflood was initiated i the western half of the field in May 2004 and efforts are underway to expand the flood to the easter 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 th 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 g 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 Coun 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 o 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 Wolfcam 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 water per day and oil production in this long-life property has remained relatively flat for many yea Modifications have recently been completed increasing the fluid handling capability of the facilitie 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 merge
we issued approximately 2.2 million shares of our common stock to Equity s shareholders and rep
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 Equ 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 bene 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 tha
the 2003 rate of 8,144 barrels per month. We plan to continue to utilize the water shut-off technolo
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 o 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 Bakken, Nisku and Red River Formations. The Roosevelt Creek Prospect that Equity had develope 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.

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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 develope 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 amende the existing spacing rules to allow up to 8 wells per section. As a result of this spacing change, the 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. Durin 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 o 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 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 millio and estimated proved reserves of 39.8 Bcfe on the effective date of the acquisition, we acquired the properties for approximately $1.11 per Mcfe of estimated proved reserves.

One of the acquired fields, Hiawatha West, located in Moffat County, Colorado contains additiona 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 prov undeveloped locations exist in the field.

Wyoming and Utah Properties. On September 30, 2004, we acquired interests in three operated fie in Wyoming and Utah from an undisclosed seller. The purchase price was $35.0 million in cash an was funded under our bank credit agreement. As of October 1, 2004, these interests had 32.6 Bcfe 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 milli 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 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 o 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 ha 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 whic 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 ar 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 o properties that we believe to have exploitation and development potential comparable to our existi 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 prove reserves. To secure attractive realized commodity prices on a portion of our volumes, we periodica 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 ha increased our volumes subject to these collars to cover approximately 56% to 58% (excluding fixe price marketing contracts) of our natural gas volumes as of October 1, 2004 through December 200 and between 55% and 75% of our crude oil volumes as of October 1, 2004 through December 200 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-ta 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 Mcf 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 o 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 wi 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 geographica areas and in all of our operational disciplines. In addition, each of our acquisition professionals has 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 seism imaging and interpretation. Our technical team has access to approximately 575 square miles of 3-I seismic data that we have assembled primarily over the past five years. A team with access to state the art geophysical/geological computer applications and hardware analyzes this information. Computer applications, such as the WellView® software system, enable us to quickly generate repo and schematics on our wells. In addition, our information systems enable us to update our producti databases through daily uploads from hand held computers in the field. This technology and expert 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)	Futur Capita Expendit (In thousa
Gulf Coast/Permian Basin:						
PDP	4,300	52,322	78.1	17.8%	$ 172,347	$ 2,7
PDNP	287	6,232	8.0	1.8%	20,465	1,1
PUD	939	30,856	36.4	8.3%	73,933	25,7
Total Proved:	5,526	89,410	122.5	27.9%	$ 266,745	$ 29,7
Rocky Mountains:						
PDP	18,898	13,183	126.6	28.8%	$ 169,051	$ 7
PDNP	571	205	3.6	0.8%	4,340	3
PUD	7,008	4,257	46.3	10.6%	87,680	18,7
Total Proved:	26,477	17,645	176.5	40.2%	$ 261,071	$ 19,9
Michigan:						
PDP	469	76,263	79.1	18.0%	$ 133,618	$
PDNP	140	6,914	7.8	1.8%	23,854	1,7
PUD	536	24,017	27.2	6.2%	56,935	14,7
Total Proved:	1,145	107,194	114.1	26.0%	$ 214,407	$ 16,4

Mid-Continent:						
PDP	1,438	15,900	24.5	5.6%	$ 41,271	$
PDNP	53	863	1.2	0.3%	1,129	2
Total Proved:	1,491	16,763	25.7	5.9%	$ 42,400	$ 2
Total Corporate:						
PDP	25,105	157,668	308.3	70.2%	$ 516,287	$ 3,5
PDNP	1,051	14,214	20.6	4.7%	49,788	3,4
PUD	8,483	59,130	109.9	25.1%	218,548	59,3
Total Proved:	34,639	231,012	438.8	100%	$ 784,623	$ 66,3

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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. W 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 Bc of net proved reserves primarily within the Word North field, the Yoakum field and the Kawitt fiel Since June 30, 2004, we have completed two successful Edwards wells in our Stuart City Reef Tre 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 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 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 field 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, poro 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 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 reservoi 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 existi wellbore that was

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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 ha produced results exceeding those of the Stillwater well. We are currently employing two drilling ri 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 a 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 t 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 bas We operate the majority of our non-Antrim production as well as the West Branch and Stoney Poi 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 presen 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). W 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 ar
structurally trapped hydrocarbon accumulations and to date recoveries range from 4% to 37% of th
in place hydrocarbons. Our undeveloped proved reserve potential in these three fields is estimated
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-Contin
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 scatte
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 Magno 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 Acreag	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Ne**
Gulf Coast/Permian Basin	159,603	58,813	8,514	7,518	168,117	66,3
Rocky Mountains	137,038	66,507	286,000	90,400	423,038	156,9
Michigan	179,141	59,000			179,141	59,0
Mid-Continent	40,740	21,438	91,284	90,395	132,024	111,8
Total	516,522	205,758	385,798	188,313	902,320	394,0

Production History

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

	Year Ended December 3		
	2003	**2002**	**200**
Oil production (MMbbls)	2.6	2.3	
Natural gas production (Bcf)	21.6	21.4	1
Total production (Bcfe)	37.2	35.2	3
Daily production (MMcfe/d)	101.8	96.4	8
Average sales prices:			
Natural gas (per Mcf)(1)	$ 4.78	$ 3.21	$ 3
Oil (per Bbl)(1)	$ 27.50	$ 23.35	$ 23
Total (per Mcfe)(1)	$ 4.73	$ 3.48	$ 3
Costs and expenses (per Mcfe):			
Lease operating expenses	$ 1.16	$ 0.93	$ 0
Production taxes	$ 0.29	$ 0.21	$ 0

Depreciation, depletion and amortization expense	$ 1.11	$ 1.24	$ 1
General and administrative expenses, net of reimbursements	$ 0.34	$ 0.34	$ 0

(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 Well	
	Gross	Net	Gross	Net	Gross	Ne
Gulf Coast/Permian Basin	1,571	139.7	852	282.0	2,423	42
Rocky Mountains	863	254.7	115	17.9	978	27
Michigan	78	57.0	968	368.3	1,046	42
Mid-Continent	372	151.2	187	78.8	559	23
Total	2,884	602.6	2,122	747.0	5,006	1,34

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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 futu performance, nor should it be assumed that there is necessarily any correlation between the numbe of productive wells drilled and quantities of reserves found or economic value. Productive wells ar those that produce commercial quantities of hydrocarbons, whether or not they produce a reasonab 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	20
Gross:														
Productive	22	10	22	2	3	3	25	7	31	15	4	64	24	
Dry	3	6	6				5	3	2			8	9	
Total	25	16	28	2	3	3	30	10	33	15	4	72	33	
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	1
Dry	.9	2.2	1.9				3.0	2.1	1.9			3.9	4.3	
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	2

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 secure 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, technic 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 natura 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 financi 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 competitic 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. I 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 th 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 a 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 natura 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 issue Order No. 636 and a series of related orders to implement its open access policies. As a result of th Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. T interstate pipelines traditional role as wholesalers of natural gas has been eliminated and replaced a structure under which pipelines provide transportation and storage service on an open access basi to others who buy and sell natural gas. Although the FERC s orders do not directly regulate natura 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 releasec 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 beer accepted by the FERC and placed into effect. While most major aspects of Order No. 637 have bee 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 thes 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 carry out this Act s mandate is to increase transparency in the market to provide producers and shippers the outer continental shelf with greater assurance of open access services on pipelines located on th 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. Howeve we do not believe that any action taken will affect us in a way that materially differs from the way affects other natural gas producers.

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Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The basis f intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutin 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 ga 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 a 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 ind 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 th 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 a shippers requesting service on the same terms and under the same rates. When oil pipelines operate full capacity, access is governed by prorationing provisions set forth in the pipelines published ta Accordingly, we believe that access to oil pipeline transportation services generally will be availab 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 requi 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 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 b 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 plan 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 requi 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 establis similar standards for royalty payments due under state oil and natural gas leases. The basis for roya 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 regulation implement and enforce such laws, which often require difficult and costly compliance measures tha 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 drillin commences, restrict the types, quantities and concentrations of various materials that can be releas 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 mo 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 curren applicable environmental laws and regulations and have not experienced any material adverse effe 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 natu 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 r 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 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 subje 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 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 ha 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 tir hydrocarbons or other materials may have been disposed or released on, under, or from the propert owned or leased by us or on, under, or from other locations where these hydrocarbons and material 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 ofter 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 stat 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 ur OPA impose strict, joint and several liability on responsible parties for damages resulting from o 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 or permittee of the area in which an offshore facility is located. The OPA establishes a liability lim for onshore facilities of $350 million while the liability limit for offshore facilities is the payment o 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 cooperat 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 $1 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 operati requirements will not have a material adverse effect on us.

Resource Conservation Recovery Act. The Resource Conservation and Recovery Act, also known a
RCRA, is the principal federal statute governing the treatment, storage and disposal of hazardou
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 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 portio 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,

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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 cost 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 dispos 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, impos 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 condu construction activities in waters and wetlands. Certain state regulations and the general permits issu under the Federal National Pollutant Discharge Elimination System program prohibit the discharge produced water, sand, drilling fluids, drill cuttings and certain other substances related to the oil an 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 perm for storm water discharges. Costs may be associated with the treatment of wastewater or developin and implementing storm water pollution prevention plans. The Clean Water Act and comparable st statutes provide for civil, criminal and administrative penalties for unauthorized discharges of oil a 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 containi facilities to prepare plans and meet construction and operating standards. The SPCC regulations we revised in 2002 and will require the amendment of SPCC plans, if necessary to ensure compliance, February 2006 with the implementation of such amended plans in August 2006. We believe that ou 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 implementatio 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 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 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 hold or have applied for all permits necessary to our operations.

Consideration of Environmental Issues in Connection with Governmental Approvals. Our operatio 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 geoscientis 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 materia

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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 Secreta
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 that position through April 1993. In March 1993, he became a contract consultant to us and served 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 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 financ 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 priv consulting firm. Mr. Casperson has twenty-six years of financial and operational experience in the 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 ha 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.

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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 Certifi Professional Landman.

J. Douglas Lang joined us in December 1999 as Senior Acquisition Engineer and became Manager 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 o 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 Exploration and Development in December 1999. He has twenty-three years of experience in the o 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 Schoo 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 Treasur at Inland Resources Inc., a company engaged in oil and natural gas exploration and development. H spent seven years in public accounting with Coopers & Lybrand in Minneapolis, Minnesota. He is 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 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 Li 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 an 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 ha 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 a 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 an 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 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 Se 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 serv 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 h was appointed Vice President of International Business for IES Diversified. From 1978 to late 197 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. 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 ar 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 fo the appointment, retention, compensation, evaluation and termination of our independent auditors a 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 o 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 committe financial expert, as defined by Securities and Exchange Commission rules.

The Compensation Committee discharges the responsibilities of our board of directors with respec 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 Messrs. Hubbard (Chairperson), Ladd and Whiting, each of whom is an independent director unde 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 directorshi identify directors qualified to serve on board committees and recommend to t our board of director members for each committee, develop and recommend to our board of directors a set of corporatio governance guidelines and otherwise take a leadership role in shaping our corporate governance. T 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 boa of directors or board committees. Directors who are not our employees are paid an annual retainer $20,000, an annual grant of $30,000 in restricted stock vesting ratably over a three year period and fee of $1,500 for each board of directors meeting attended. Members of the Audit Committee recei an additional cash annual retainer of $2,500 ($12,000 for the chairman) and a fee of $1,500 for eac 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 employ 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 compensate 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($**
James J. Volker				
	2003	168,713	262,792	659,0
President and Chief Executive Officer	2002	165,000	205,041	
D. Sherwin Artus	2003	102,250	183,211	680,0
	2002	173,309	156,641	11,0

Senior Vice President				
John R. Hazlett				
	2003	115,952	139,133	653,0
Vice President, Acquisitions and Land	2002	112,050	114,941	11,0
Mark R. Williams				
	2003	95,406	150,672	626,0
Vice President, Exploration and Development	2002	91,510	124,819	11,0
Patricia J. Miller				
Vice President, Human Resources and	2003	99,579	138,930	427,9
Corporate Secretary	2002	96,228	114,630	11,0

(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 ga wells.

(2) These amounts for 2003 consist of (i) matching contributions of $12,000 by us under our 401(l 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 M Volker, 25,394 shares to Mr. Artus, 24,368 shares to Mr. Hazlett, 23,341 shares to Mr. William and 15,814 shares to Ms. Miller. The Phantom Equity Plan terminated after the issuance of suc shares.

Compensation Committee Interlocks and Insider Participation

During 2003, Graydon D. Hubbard, J.B. Ladd and Kenneth R. Whiting served on the Compensatio 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 l one or more of its executive officers serving as a member of our board of directors or compensatio committee.

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PRINCIPAL HOLDERS OF COMMON STOCK

Set forth below is information regarding the beneficial ownership of Whiting Petroleum Corporatio common stock by Resources, each of our directors and executive officers, all directors and executi 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 i 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 shar 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 wit 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 sale of the shares offered by Resources in this offering.

	Shares of Common Stock Beneficially Owned Prior to this Offering			Shares of Common S Beneficially Own After this Offering	
Name	Number	Percent	Number of Shares Being Offered	Number	Perc
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-owr subsidiary, Resources.

Management and Directors

The following table sets forth certain information regarding the beneficial ownership of our comm stock as of October 26, 2004 by: (i) each of our directors; (ii) each of the executive officers named the Summary Compensation Table set forth under Management Executive Compensation ; and 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 perso known to Whiting to own more than 5% of its outstanding common stock other than Alliant Energ and Resources. The beneficial ownership information set forth below is as reported in filings made the beneficial owners with the Securities and Exchange Commission.

Name and Address of Beneficial Owner	Amount and Nature of Beneficial Ownership: Voting Power: Sole	Voting Power: Shared	Investment Power: Sole	Investment Power: Shared	Aggregate	Percen of Clas
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 sol 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 Ga 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 pub 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 inter at a fixed rate equal to 5.0% per year and the entire unpaid balance, together with interest, will be d and payable November 25, 2005.

The master separation agreement provides that we were responsible for withholding from payment 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 agen 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 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 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 o 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 feder 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 completio 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 ta 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 a 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 Corporati and its subsidiaries

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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 thi 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 u had the increase in basis not occurred. In 2014, we will be obligated to pay Alliant Energy the pres value of the remaining tax benefits assuming all such tax benefits will be realized in future years. T initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferr 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 registration 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 u then we may postpone filing a registration statement for up to 45 days once in a twelve month peri 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 custom limitations. All expenses payable in connection with such registrations will be paid by us, except th 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, the 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 guarantee 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 valu per share.

The following summary of the capital stock and certificate of incorporation and by-laws of Whitin Petroleum Corporation does not purport to be complete and is qualified in its entirety by reference 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. Holder of our common stock are entitled to one vote for each share held on all matters submitted to a vote 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 directo 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 ne 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 ser 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 designat and issue shares of preferred stock in one or more series without stockholder approval. Our board o directors has discretion to determine the rights, preferences, privileges and restrictions, including voting rights, dividend rights, conversion rights, redemption privileges and liquidation preferences each series of preferred stock. It is not possible to state the actual effect of the issuance of any shar 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 tran 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 th 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 other transactions resulting in a financial benefit to the interested stockholder. Subject to

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certain exceptions, an interested stockholder is a person who, together with affiliates and associ 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 certificat 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 voti 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 witho 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 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 Sect 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 no good faith or which involve intentional misconduct or a knowing violation of law, (3) under Sectio 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 liabilit 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 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 attra 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

The selling stockholder intends to offer the shares through Merrill Lynch, Pierce, Fenner & Smith Incorporated. Subject to the terms and conditions described in a purchase agreement among us, Alliant Energy, the selling stockholder and Merrill Lynch, the selling stockholder has agreed to sel to Merrill Lynch, and Merrill Lynch has agreed to purchase from the selling stockholder, all 1,080,000 shares offered hereby.

Merrill Lynch has agreed to purchase all of the shares sold under the purchase agreement if any of these shares are purchased.

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

Merrill Lynch is 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 Merrill Lynch of offic certificates and legal opinions. Merrill Lynch reserves the right to withdraw, cancel or modify offe to the public and to reject orders in whole or part.

Commissions and Discounts

Merrill Lynch has advised the selling stockholder that it proposes 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 le a concession not in excess of $.52 per share. Merrill Lynch may allow, and the dealers may reallow discount not in excess of $.10 per share to other dealers. After the public offering, the public offeri price, concession and discount may be changed.

The following table shows the public offering price, underwriting discount and proceeds before expenses to the selling stockholder.

	Per Share	Total
Public offering price	$29.02	$31,341,600
Underwriting discount	$.8706	$940,248
	$28.1494	$30,401,352

Proceeds, before expenses, to the selling stockholder

The expenses of the offering and our concurrent primary offering, 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 this offering by the selling stockholder.

No Sale of Similar Securities

We, the selling stockholder, 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. Specifically, we and these other individuals ha 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,

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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 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 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 agreem 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 Merrill Lynch and selling gro members from bidding for and purchasing our common stock. However, Merrill Lynch may engag in transactions that stabilize the price of the common stock, such as bids or purchases to peg, fix or maintain that price.

If Merrill Lynch creates a short position in the common stock in connection with the offering, i.e., it sells more shares than are listed on the cover of this prospectus, Merrill Lynch may reduce that short position by purchasing shares in the open market. 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.

Neither we nor Merrill Lynch makes any representation or prediction as to the direction or magnitu of any effect that the transactions described above may have on the price of the common stock. In addition, neither we nor Merrill Lynch makes any representation that the representative will engag 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 maintain 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

Merrill Lynch and its affiliates have engaged in, and may in the future engage in, investment banki and other commercial dealings in the ordinary course of business with us and with Alliant Energy. They have received customary fees and commissions for these transactions. In particular, an affilia of Merrill Lynch, Pierce, Fenner & Smith Incorporated, is a lender under Alliant Energy s bank cr facilities.

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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 lega 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) an have been so included in reliance upon the report of such firm given upon their authority as expert 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 hav been audited by Deloitte & Touche LLP, an independent registered public accounting firm, as state 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 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. Th prospectus, which constitutes part of the registration statement, does not contain all the informatior set forth in the registration statement or the exhibits and schedules which are part of the registratior 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 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 m 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 consolidate statements of income, stockholder s equity and comprehensive income, and cash flows for each of three years in the period ended December 31, 2003. These financial statements are the responsibilit 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 obt 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 significan 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 materi respects, the financial position of the Company as of December 31, 2003 and 2002, and the results its operations and its cash flows for each of the three years in the period ended December 31, 2003 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	$ 4,82
Accounts receivable trade	24,020	22,50
Income taxes and other receivables		8,16
Prepaid expenses and other	2,666	3,54
Total current assets	80,271	39,04
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	615,764	553,90
Unproved properties	1,637	1,59
Other property and equipment	2,684	3,43
Total property and equipment	620,085	558,94
Less accumulated depreciation, depletion and amortization	(192,794)	(154,33
Property and equipment net	427,291	404,59
OTHER LONG-TERM ASSETS	9,988	4,82
DEFERRED INCOME TAX ASSET	18,735	
TOTAL	$ 536,285	$ 448,46

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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	$ 8,47
Oil and gas sales payable	2,406	90
Accrued employee benefits	5,275	4,2
Production taxes payable	2,574	2,1
Derivative liability	2,145	3,30
Income taxes and other liabilities	693	5
Total current liabilities	29,011	19,6
DEFERRED INCOME TAX LIABILITY		28,2
ABANDONMENT LIABILITY	23,021	4,2
PRODUCTION PARTICIPATION PLAN LIABILITY	7,868	8,0
TAX SHARING LIABILITY	28,790	
LONG-TERM DEBT	188,017	265,47
COMMITMENTS AND CONTINGENCIES (Note 7)		
STOCKHOLDERS EQUITY:		
Common stock, $.001 par value; 18,750,000 authorized, issued and outstanding	19	[illegible]
Additional paid-in capital	170,367	53,2
Accumulated other comprehensive loss	(223)	(1,5
Retained earnings	89,415	71,1
Total stockholders equity	259,578	122,8
TOTAL	$ 536,285	$ 448,4

See notes to consolidated financial statements.

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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	$ 125,2
Gain (loss) on oil and gas hedging activities	(8,680)	(3,184)	2,2
Gain on sale of oil and gas properties		978	11,6
Interest income and other	330	9	2
Total	167,381	120,512	139,4
COSTS AND EXPENSES:			
Lease operating	43,213	32,867	29,7
Production taxes	10,691	7,363	6,4
Depreciation, depletion and amortization	41,256	43,601	26,9
Exploration	3,186	1,811	7
General and administrative	12,805	11,980	10,9
Phantom equity plan	10,914		
Interest expense	9,177	10,938	10,2
Total costs and expenses	131,242	108,560	85,1
INCOME BEFORE INCOME TAXES	36,139	11,952	54,3
INCOME TAX EXPENSE (BENEFIT):			
Current	2,389	(6,408)	1,8
Deferred	11,560	10,631	11,2
Total income tax expense	13,949	4,223	13,0
INCOME FROM CONTINUING OPERATIONS	22,190	7,729	41,2
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	(3,905)		
NET INCOME	$ 18,285	$ 7,729	$ 41,2
Basic and diluted earnings per share from continuing operations	$ 1.18	$ 0.41	$ 2
Cumulative change in accounting principle	(0.20)		
BASIC AND DILUTED NET INCOME PER COMMON SHARE	$ 0.98	$ 0.41	$ 2
WEIGHTED AVERAGE SHARES OUTSTANDING	18,750	18,750	18,7

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		Additional		Accumulated Other Comprehensive	Total	
	Shares	Amount	Paid-in Capital	Retained Earnings	Income (Loss)	Stockholders Equity	Comprehen Incom
BALANCES January 1, 2001	18,750	$ 19	$ 47,856	$ 22,158	$ 15	$ 70,048	
Net income				41,243		41,243	41,24
Unrealized net gain on marketable equity securities for sale					88	88	8
Reclass to earnings					87	87	8
BALANCES December 31, 2001	18,750	19	47,856	63,401	190	111,466	41,4
Net income				7,729		7,729	7,72
Unrealized net gain on marketable equity securities for sale					240	240	24
Tax contribution from Alliant			5,363			5,363	
Change in derivative instrument fair value					(1,980)	(1,980)	(1,98
BALANCES December 31, 2002	18,750	19	53,219	71,130	(1,550)	122,818	5,98
Net income				18,285		18,285	18,28
Unrealized net gain on marketable equity securities for sale					664	664	66
Change in derivative instrument fair value					663	663	66
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	$ 19,6

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	$ 41,24
Adjustments to reconcile net income to net cash provided by operating activities:			
Gain on sale of oil and gas properties		(978)	(11,70
Depreciation, depletion and amortization	41,256	43,601	35,90
Deferred income taxes	11,560	10,631	11,28
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)	2,16
Income taxes and other receivable	3,814	1,538	(5,67
Other assets	295	(1,229)	31
Abandonment liability	(147)	(48)	(8,99
Production participation plan	651	1,685	1,47
Current liabilities	9,229	710	(3,67
Net cash provided by operating activities	96,362	62,581	62,34
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(47,555)	(165,443)	(99,62
Acquisition of partnership interests, net of cash received	(4,453)		
Proceeds from sale of properties		1,534	19,57
Restricted cash		6,434	(6,43
Net cash used in investing activities	(52,008)	(157,475)	(86,48
CASH FLOWS FROM FINANCING ACTIVITIES:			
Other advances (repayments) from Alliant, net	4,616	(83,119)	23,86
Proceeds from bank loan		185,000	
Debt issuance costs	(218)	(3,171)	
Net cash provided by financing activities	4,398	98,710	23,86
NET CHANGE IN CASH AND CASH EQUIVALENTS	48,752	3,816	(26
CASH AND CASH EQUIVALENTS:			
Beginning of period	4,833	1,017	1,28

End of period	$ 53,585	$ 4,833	$ 1,0
SUPPLEMENTAL CASH FLOW DISCLOSURES:			
Cash paid (refunded) for income taxes Alliant	$ (1,425)	$ (7,946)	$ 8,5
Cash paid for interest	$ 6,464	$ 10,866	$ 10,2
NONCASH FINANCING ACTIVITIES:			
Alliant debt converted to equity	80,931		

See notes to consolidated financial statements.

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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)

1. SUMMARY OF SIGNIFICANT ACCOUNTING POLICIES

Description of Operations Whiting Petroleum Corporation (Whiting or the Company) is a D 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 wh 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 oth 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 statemen include the accounts of Whiting and its subsidiaries, all of which are wholly owned, together with pro rata share of the assets, liabilities, revenue and expenses of limited partnerships in which Whiti 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 principle 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 o gas or rate of production or increase in costs associated with the operations of oil and gas propertie 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 c equivalents, restricted cash, accounts receivable and payable are carried at cost, which approximate 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 ar 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 economi 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. Th 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 reduce volatility in our reported results of operations, financial position and cash flows from period to per and lowers our overall business risk; but, as a result of Whiting s hedging activities the Company 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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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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(In thousands, except per share data)

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

Oil and Gas Producing Activities The Company follows the successful efforts method of account 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 o whether the well has found proved reserves. If an exploratory well has not found proved reserves, t costs of drilling the well and other associated costs are charged to expense. The costs of developm wells are capitalized whether productive or nonproductive.

Interest cost is capitalized as a component of property cost for exploration and development projec that require a period of time to be reaided 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 i 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 bas using the units of production method based upon proved reserves. The computation of DD&A take into consideration the anticipated proceeds from equipment salvage and the Company s expected 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 impairmen 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 c 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 discou 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. Sale of partial interests are generally treated as recoveries of costs.

Other Property and Equipment Other property and equipment are stated at cost and depreciated u 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 oth property and equipment is sold or retired, the related costs and accumulated depreciation are remov 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 li the loan.

Reimbursed Overhead The Company provides various administrative services to its partnerships 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 143, *Accounting for Asset Retirement Obligations*. This Statement generally applies to legal obligations

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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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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 Compan 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 intere well bores. The additional carrying amount is depleted over the estimated lives of the properties. T 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 revenu recognized based on the amount of oil sold to purchasers. The Company uses the entitlements meth to record natural gas revenues whereby revenue is recognized for the Company s share of natural produced, regardless of whether the Company has taken its share of the related revenue. In situatio 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. 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 producti 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 oi and gas prices. Periodically, Whiting utilizes oil and gas swaps and forward contracts to mitigate th impact of oil and gas price fluctuations related to its sales of oil and gas. During the years 2003, 20 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 o accumulated other comprehensive loss and $828 was recorded as an increase to the deferred tax as

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 o 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 approximat
$8.7 million, a loss of approximately $3.2 million, and a gain of $2.3 million from the settlement o
derivative instruments, respectively.

Marketable Securities Investments in marketable securities are classified as held-to-maturity, trad
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 incon

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 t
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 an $285 was recorded as a deferred tax liability.

Income Taxes Prior to the Company s initial public offering in November 2003, the Company w included in the consolidated federal income tax return of Alliant Energy but was treated as a separa entity for income tax purposes. The Company provides deferred federal and state income taxes on 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 incor per common share of stock is calculated by dividing net income by the weighted average of comm 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 (FA issued SFAS No. 141, *Business Combinations* which requires the purchase method of accounting f business combinations initiated after June 30, 2001 and eliminates the pooling-of-interests method 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 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 3 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 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 Dispos* *Activities*. This Statement addresses financial accounting and reporting for costs associated with ex 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 effectiv 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 200 by the FASB. FIN 45 requires a guarantor to recognize a liability for the fair value of the obligatio 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 guarante the maximum

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(In thousands, except per share data)

exposure under the guarantee, the current carrying amount of any liability for the guarantee, and an recourse provisions allowing the guarantor to recover from third parties any amounts paid under th guarantee. The disclosure provisions of FIN 45 are effective for financial statements for both interi 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, 20 The adoption of this Statement did not have a material impact on the financial statements. Under th disclosure provisions, the Company, as part of a 2002 purchase transaction, agreed to share with th seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barr 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 exces 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. of December 31, 2003, the Company has paid $3.1 million under this agreement and has accrued a 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 Accountin 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 ot parties. FIN 46 requires existing unconsolidated variable interest entities to be consolidated by thei 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 o 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 fo 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 eithe 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 impac 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 statements of financial position. The financial instruments are mandatorily redeemable shares, whi 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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(In thousands, except per share data)

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 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 o $80,931 to equity of the Company. The Company incurred approximately $1.2 million, $10.5 milli and $10.2 million, in interest expense related to this note during the years ended December 31, 200 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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WHITING PETROLEUM CORPORATION AND SUBSIDIARIES

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(In thousands, except per share data)

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 developmen The amounts due from/to affiliates represent the net amount of advances to partnerships for proper development offset by proceeds on sales of property and cash receipts from the sale of oil and gas 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,(
Alliant see Note 4	3,017	80,4

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 o the Company s proved reserves and is subject to redetermination on May 1 and November 1 of ea 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 inter only payments until December 20, 2005, when the entire amount borrowed is due. Interest accrues the Company s option, at either (1) the base rate plus a margin where the base rate is defined as th higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0.25% to 1. depending on the ratio of the amounts borrowed to the borrowing base, or (2) at the LIBOR rate pl 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 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 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 t 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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(In thousands, except per share data)

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 calend year. This plan prohibits the repricing of outstanding stock options without stockholder approval. A 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 p 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 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 contribution 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, $9 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 wa 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 th 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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Tax Separation and Indemnification Agreement with Alliant Energy In connection with Whiting 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 Alli 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 ta basis of the Company s assets. This additional basis is expected to result in increased future incom tax deductions and, accordingly, may reduce income taxes otherwise payable by Whiting. Under th 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 remaini tax benefits assuming all such tax benefits will be realized in future years. Future tax benefits in to 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 l 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 increa to stockholders equity. The Company will monitor the estimate of when payments will be made a adjust the accretion of this liability on a prospective basis. There is a provision in the Tax Separatio Agreement that if tax rates were to change (increase or decrease), the tax benefit or detriment woul 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 cumulat 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 difference 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 fede income tax return of Alliant Energy and calculated its income tax expense on a separate return basi 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 separat 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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(In thousands, except per share data)

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

	2003	2002	2001
Expected statutory tax expense at 35%	$ 12,649	$ 4,183	$ 19,0
Research and Section 29 tax credits		(178)	(6,5
Excess percentage depletion	(216)	(82)	(2
State tax expense, net of federal benefit	1,516	300	9
	$ 13,949	$ 4,223	$ 13,0

Temporary differences between the financial statement carrying amounts and tax bases of assets ar 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 ir 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	$ 553,9
Unproven oil and gas properties	1,637	1,5
Accumulated depreciation, depletion and amortization	(191,488)	(152,5
Oil and gas properties net	$ 425,913	$ 402,9

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 accorda 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 inherent 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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(In thousands, except per share data)

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

	Oil (Mbbls)	Gas (Mm
Balance January 1, 2001	19,121	157,52
Extensions and discoveries	1,086	9,32
Sales of minerals in place	(677)	(6,04
Purchases of minerals in place	945	89,76
Production	(2,088)	(19,75
Revisions to previous estimates	(3,582)	(3,28
Balance December 31, 2001	14,805	227,52
Extensions and discoveries	473	2,34
Sales of minerals in place		(93
Purchases of minerals in place	15,244	58,38
Production	(2,319)	(21,36
Revisions to previous estimates	1,255	(29,94
Balance December 31, 2002	29,458	235,98
Extensions and discoveries	2,327	17,09
Sales of minerals in place		
Purchases of minerals in place	822	3,99
Production	(2,594)	(21,59
Revisions to previous estimates	4,627	(4,47
Balance December 31, 2003	34,640	231,01
Proved developed reserves:		
December 31, 2001	11,046	136,81
December 31, 2002	23,784	167,61
December 31, 2003	26,157	171,88

As discussed in Note 6 Employee Benefit Plans, all of the Company s employees participate i Company s production participation plan. The reserve disclosures above include oil and gas reser 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 royal interest while allocations since 1995 have been 2% 5% of net income from the oil and gas product allocated to the plan.

The standardized measure of discounted future net cash flows relating to proved oil and gas reserve 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 pret net cash flows relating to proved oil and gas reserves, less the tax basis of properties involved. Futu income

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(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 deriv 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 gas properties.

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

	2003	2002	2001
Future cash flows	$ 2,297,935	$ 1,854,886	$ 880,89
Future production costs	(879,390)	(677,146)	(379,7
Future development costs	(66,326)	(65,440)	(75,5
Future income tax expense	(336,165)	(270,516)	(62,0
Future net cash flows	1,016,054	841,784	363,5
10% annual discount for estimated timing of cash flows	(426,490)	(365,755)	(151,8
Standardized measure of discounted future net cash flows	$ 589,564	$ 476,029	$ 211,7

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 computation, then future cash flows would have decreased by $145 in 2003 and $1,300 in 2002 an $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	$ 519,19
Sale of oil and gas produced, net of production costs	(121,827)	(80,337)	(87,27
Sales of minerals in place		(739)	(11,20
Net changes in prices and production costs	108,115	212,191	(528,09
Extensions, discoveries and improved recoveries	47,183	6,587	17,51
Development costs-net	(886)	(11,328)	(3,32
Purchases of mineral in place	16,745	241,798	84,61
Revisions of previous quantity estimates	43,679	(36,164)	(16,20
Net change in income taxes	(42,082)	(116,854)	183,03
Accretion of discount	62,901	24,786	73,51
Changes in production rates and other	(293)	24,354	(20,03
End of year	$ 589,564	$ 476,029	$ 211,73

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

	2003	2002	200
Oil (per Bbl)	$ 29.43	$ 28.21	$ 17
Gas (per Mcf)	$ 5.52	$ 4.39	$ 2

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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 2003**
Year ended December 31, 2003:				
Oil and gas sales	$ 49,483	$ 41,883	$ 42,272	$ 42,0
Income (loss) before income tax and cumulative effect of change in accounting principle	11,935	11,481	12,885	(1
Cumulative effect of change in accounting principle	(3,905)			
Net income (loss)	3,559	7,053	7,989	(3
Basic net income (loss) per share	0.19	0.38	0.43	(0.

	Three Months Ended			
	March 31, 2002	**June 30, 2002**	**September 30, 2002**	**December 2002**
Year ended December 31, 2002:				
Oil and gas sales	$ 20,190	$ 29,552	$ 34,657	$ 38,
Income (loss) before income tax	(2,977)	3,277	6,191	5,
Net income	(1,822)	2,050	3,877	3,
Basic net income (loss) per share	(0.10)	0.11	0.21	0

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 3 2003
ASSETS		
CURRENT ASSETS:		
Cash and cash equivalents	$ 17,361	$ 53,58
Accounts receivable trade, net	35,322	24,02
Prepaid expenses and other	6,488	2,66
Total current assets	59,171	80,27
PROPERTY AND EQUIPMENT:		
Oil and gas properties, successful efforts method:		
Proved properties	1,193,090	615,76
Unproved properties	4,325	1,62
Other property and equipment	3,616	2,68
Total property and equipment	1,201,031	620,08
Less accumulated depreciation, depletion and amortization	(225,275)	(192,79
Total property and equipment-net	975,756	427,29
OTHER LONG-TERM ASSETS	19,624	9,98
DEFERRED INCOME TAX ASSET		18,71
TOTAL	$ 1,054,551	$ 536,28

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 3 2003
LIABILITIES AND STOCKHOLDERS EQUITY		
CURRENT LIABILITIES:		
Accounts payable	$ 23,280	$ 15,91
Oil and gas sales payable	4,051	2,40
Accrued employee benefits	4,788	5,27
Production taxes payable	7,580	2,57
Derivative liability	9,850	2,14
Income taxes and other liabilities	200	69
Current portion of long-term debt	50,000	
Total current liabilities	99,749	29,01
ASSET RETIREMENT OBLIGATIONS	30,502	23,02
PRODUCTION PARTICIPATION PLAN LIABILITY	8,833	7,86
TAX SHARING LIABILITY	30,590	28,79
LONG-TERM DEBT	538,827	188,01
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	
Additional paid-in capital	216,120	170,36
Accumulated other comprehensive loss	(6,050)	(22
Deferred compensation	(2,035)	
Retained earnings	126,841	89,41
Total stockholders equity	334,897	259,57
TOTAL	$ 1,054,551	$ 536,28

See notes to unaudited consolidated financial statements.

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	$ 133,62
Loss on oil and gas hedging activities	(2,040)	(151)	(3,615)	(8,9
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	1
Total	67,290	42,208	168,741	124,8
COSTS AND EXPENSES:				
Lease operating	12,957	11,288	34,650	32,1
Production taxes	3,950	2,560	10,168	8,1
Depreciation, depletion and amortization	13,010	10,212	34,500	30,6
Exploration and impairment	3,766	280	4,686	1,0
General and administrative	6,117	3,126	14,191	9,5
Interest expense	4,172	1,856	9,591	7,1
Total costs and expenses	43,972	29,322	107,786	88,5
INCOME BEFORE INCOME TAXES AND CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	23,318	12,886	60,955	36,3
INCOME TAX EXPENSE:				
Current	400	208	400	6
Deferred	8,601	4,688	23,129	13,1
Total income tax expense	9,001	4,896	23,529	13,7
INCOME FROM CONTINUING OPERATIONS	14,317	7,990	37,426	22,5
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE (See Note 4)				(3,9
NET INCOME	$ 14,317	$ 7,990	$ 37,426	$ 18,6
	$ 0.70	$ 0.43	$ 1.93	$ 1.

Earnings per share from continuing operations, basic and diluted				
Cumulative change in accounting principle				(0.2
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 0.70	$ 0.43	$ 1.93	$ 0.9
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	20,516	18,750	19,341	18,75
WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	20,554	18,750	19,370	18,75

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		Additional Paid-in	Retained	Accumulated Other Comprehensive Income	Deferred	Total Stockholders	Comprehe
	Shares	Amount	Capital	Earnings	(Loss)	Compensation	Equity	Incon
BALANCES January 1, 2003	18,750	$ 19	$ 53,219	$ 71,130	$ (1,550)	$	$ 122,818	
Net income				18,285			18,285	$ 18,2
Unrealized net gain on marketable securities for sale					664		664	6
Change in derivative instrument fair value					663		663	6
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	$ 19,6
Net income (unaudited)				37,426			37,426	$ 37,4
Change in fair value of marketable securities for sale (unaudited)					3,741		3,741	3,7
Realized net gain on marketable securities for sale (unaudited)					(4,835)		(4,835)	(4,8
Change in derivative instrument fair value (unaudited)					(4,733)		(4,733)	(4,7
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	$ 31,5

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	$ 18,6
Adjustments to reconcile net income to net cash provided by operating activities:		
Depreciation, depletion and amortization	34,500	30,6
Deferred income taxes	23,129	13,1
Amortization of debt issuance costs and debt discount	1,025	8
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		3,9
Changes in assets and liabilities:		
Accounts receivable	(6,466)	1,0
Income taxes and other receivable		2
Other assets	(3,652)	1,4
Asset retirement obligations	(321)	(1
Production participation plan liability	542	(6
Other current liabilities	12,144	5,8
Net cash provided by operating activities	96,866	74,9
CASH FLOWS FROM INVESTING ACTIVITIES:		
Cash acquisition capital expenditures	(445,340)	(6,4
Drilling capital expenditures	(52,782)	(26,6
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		(4,4
Net cash used by investing activities	(491,958)	(37,5
CASH FLOWS FROM FINANCING ACTIVITIES:		
Advances from Alliant		4
Issuance of long-term debt	583,890	
Payments on long-term debt	(214,000)	
Debt issuance costs	(11,022)	(2
Net cash provided (used) by financing activities	358,868	2
NET CHANGE IN CASH AND CASH EQUIVALENTS	(36,224)	37,6
CASH AND CASH EQUIVALENTS:		

Beginning of period	53,585	4,8
End of period	$ 17,361	$ 42,5
SUPPLEMENT CASH FLOW DISCLOSURES:		
Cash paid for income taxes	$ 885	$ 4
Cash paid for interest	$ 3,592	$ 5,7
NONCASH FINANCING ACTIVITIES:		
Issuance of common stock for Equity Oil Company common stock	$ 43,298	
Alliant debt converted to equity	$	$ 80,9

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 D 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 wh primary businesses are utility companies. Just prior to the initial public offering of Whiting s com stock, the Company in effect split its common stock, issuing 18,330 shares for the 1 previously hel 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 State

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 balanc 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 Decem 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 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 o common shares outstanding and other dilutive securities. The only securities considered dilutive ar the Company s unvested restricted stock awards. The dilutive effect of these securities was immat 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 pric
fluctuations related to its sales of oil and gas. The Company attempts to qualify the majority of the
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 $8,9
respectively, related to its hedging activities. In addition, at September 30, 2004, Whiting s remai
cash flow hedge positions resulted in a pre-tax liability of $9,850 of which $6,050 was recorded as
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
available-for-sale (included in other long term-assets). The original cost to the Company was $585
During

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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 gai 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 fo Asset Retirement Obligations. This Statement generally applies to legal obligations associated wi the retirement of long-lived assets that result from the acquisition, construction, development and/o the normal operation of a long-lived asset. SFAS No. 143 requires the Company to recognize the fa 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 a 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 th 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 prove 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 th 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.

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5. LONG-TERM DEBT

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

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

Credit Facility On September 23, 2004, Whiting Oil and Gas Corporation entered into an amende 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 cr 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 lender 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 and natural gas producing properties from CrownQuest Operating LLC. On September 30, 2004, a 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 entir 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 th principal balance to $385.0 million. Whiting Oil and Gas Corporation may, throughout the four yea 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 r 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 borrowin 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, amon 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, incu liens and engage in certain other transactions without the prior consent of the lenders and requires to maintain a debt to EBITDAX (as defined in the credit agreement) ratio of less than 3.5 to 1 and working capital ratio of greater than 1 to 1. The credit agreement also requires the Company to hed at least 60% but not more than 75% of its total forecasted proved developed producing production 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 Therm Units (MMBtu). After December 31, 2005, the credit agreement will not require us to hedge any o 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 th credit agreement allows the Company s subsidiaries to make payments to the Company so that it m 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 an Gas Corporation under the credit agreement, Whiting Petroleum Corporation has pledged the stock 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 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 complete an exchange offer in which it issued $150.0 million aggregate principal amount of new 7 1/4% seni 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 t 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 o 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 management in operating the Company s business. In addition, Whiting Oil and Gas Corporation 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 the Company s subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity 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 Guarant 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 fai value of $75 million of our 7 1/4% Senior Subordinated Notes due 2012. Because this swap meets t 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 assum 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 pa 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 si 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. A 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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Long-Term Debt Payable to Alliant Energy In conjunction with the Company s initial public off in November 2003, the Company issued a promissory note payable to Alliant Energy in the aggreg 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 200 On March 31, 2003, Alliant Energy converted its outstanding intercompany balance of $80.9 milli 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 calend 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 und 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 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. Allocation 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

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 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 immediate prior to such initial public offering. Whiting has adjusted deferred taxes on its balance sheet to refl 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 c or prior to

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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 Allia 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 increa to stockholders equity. The Company will monitor the estimate of when payments will be made a adjust the accretion of this liability on a prospective basis. During the first nine months of 2004, th Company recognized $1.8 million of accretion expense which is included as a component of intere 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 Te 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 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 MMcf 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 merge we issued approximately 2.2 million shares of our common stock to Equity s shareholders and rep 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.

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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 funde 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 reser of 39.8 Bcfe on the effective date of the acquisition, we acquired these properties for approximatel $1.11 per Mcfe of estimated proved reserves.

On September 30, 2004, we acquired interests in three operated fields in Wyoming and Utah from 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 reserve and estimated October 2004 average daily production of 6.1 MMcfe, implying an average reserve l 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 ba 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 o 11.0 years. Based on the purchase price of $19.3 million and estimated proved reserves of 12.0 Bcf 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 assum (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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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 amou 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 Consolida
Year ended December 31, 2003					
Total revenues	$ 167,381	$ 91,246	$ 27,825	$ 28,592	$ 315,0
Net income from continuing operations	22,190	19,028	6,050	3,823	51,0
Net income	18,285	19,028	6,050	3,823	47,1
Net income per common share-basic and diluted	0.98	0.91	0.29	0.18	2
Three months ended September 30, 2004					
Total revenues	$ 67,290	$ 19,300	$ 1,489	$ 6,123	$ 94,2
Net income	14,317	4,649	377	1,205	20,5
Net income per common share-basic and diluted	0.70	0.22	0.02	0.06	0
Three months ended September 30, 2003					
Total revenues	$ 42,208	$ 21,476	$ 6,705	$ 7,117	$ 77,5
Net income	7,990	4,733	1,408	955	15,0
Net income per common share-basic and diluted	0.43	0.23	0.07	0.05	0
Nine months ended September 30, 2004					
Total revenues	$ 168,741	$ 58,443	$ 15,980	$ 23,553	$ 266,7
Net income	$ 37,426	$ 11,614	$ 4,047	$ 4,457	$ 57,5
Net income per common share-basic and diluted	$ 1.93	$ 0.55	$ 0.19	$ 0.21	$ 2

Nine months ended September 30, 2003					
Total revenues	$ 124,865	$ 74,070	$ 20,101	$ 21,723	$ 240,7
Net income from continuing operations	22,507	16,809	3,866	3,092	46,2
Net income	18,602	16,809	3,866	3,092	42,3
Net income per common share-basic and diluted	0.99	0.80	0.18	0.15	2

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 2004
Nine months ended September 30, 2004:			
Oil and gas sales	$ 47,636	$ 52,874	$ 65,8
Net income	9,638	13,471	14,3
Basic net income per share	0.51	0.72	0

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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 Corporati (the Company) from CQ Acquisition Partners I, L.P., SPA-CQAP II, Enerquest Oil & Gas, Ltd. Baytech, L.L.P. for each of the three years in the period ended December 31, 2003. These statemen are the responsibility of the Company s management. Our responsibility is to express an opinion o these statements based on our audits.

We conducted our audits in accordance with standards of the Public Company Accounting Oversig 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 estimat 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 ar are not intended to be a complete presentation of the Company s interests in the properties describ 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 fo 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**	**200**
	(Unaudited)				
REVENUES Oil and gas production	$ 39,143	$ 52,594	$ 91,246	$ 61,903	$ 69,6
DIRECT OPERATING EXPENSES:					
Lease operating expense	8,244	6,900	14,031	11,252	10,7
Production taxes	2,317	2,899	5,159	3,350	4,1
Total direct operating expenses	10,561	9,799	19,190	14,602	14,9
Revenues in excess of direct operating expenses	$ 28,582	$ 42,795	$ 72,056	$ 47,301	$ 54,7

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 EXPENSE

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 acquisiti 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 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 th amount of oil sold to purchasers. With respect to the gas sales, the entitlements method was used fo recording revenues. Under this approach, revenue is recognized for the Sellers share of natural ga produced regardless of whether the Sellers had taken its share of the related production. The effect revenues of production imbalances is not material. Direct operating expenses include payroll, lease 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. Su 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 Securitie and Exchange Commission Regulation S-X.

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PERMIAN BASIN ACQUISITION PROPERTIES

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSE

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 continua 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 (Mmc
Balance January 1, 2001	39,127	76,5
Production	(1,415)	(8,68
Balance December 31, 2001	37,712	67,83
Production	(1,948)	(5,33
Balance December 31, 2002	35,764	62,50
Production	(2,166)	(5,87
Balance December 31, 2003	33,598	56,62
Production	(777)	(2,4
Balance June 30, 2004	32,821	54,20
Proved developed reserves:		
December 31, 2001	23,157	52,00
December 31, 2002	21,209	46,60
December 31, 2003	19,043	40,79
June 30, 2004	18,266	38,37

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 we prepared in accordance with the provisions of SFAS No. 69. Future cash inflows were computed b applying prices at year end to estimated future production, less estimated future expenditures (base 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 n cash flows are discounted at a rate of 10% annually to derive the standardized measure of discount future net cash flows. This calculation procedure does not necessarily result in an estimate of the fa 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	$ 727,0
Future production costs	(416,440)	(429,143)	(414,8
Future development costs	(73,031)	(90,082)	(95,8
Future income tax expense	(110,581)	(89,874)	
Future net cash flows	610,897	577,960	216,3
10% annual discount for estimated timing of cash flows	(304,410)	(287,997)	(107,8
Standardized measure of discounted future net cash flows	$ 306,487	$ 289,963	$ 108,5

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PERMIAN BASIN ACQUISITION PROPERTIES

NOTES TO THE STATEMENTS OF REVENUES AND DIRECT OPERATING EXPENSE

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	$ 376,22
Sale of oil and gas produced, net of production costs	(72,056)	(47,301)	(54,7
Net changes in prices and production costs	48,413	257,159	(368,69
Development costs	17,051	5,790	3,69
Net change in income taxes	(10,389)	(45,090)	103,4
Accretion of discount	33,505	10,855	48,6
End of Year	$ 306,487	$ 289,963	$ 108,5

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

	2003	2002	200
Oil (per Bbl)	$ 28.29	$ 27.04	$ 15
Gas (per Mcf)	4.60	3.52	1

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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 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 o of crude oil, condensate or natural gas liquids.

Boe Barrels of oil equivalent, determined using the ratio of six thousand cubic feet of natural ga 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 i 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 poi 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 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 Bbl of crude oil, condensate or natural gas liquids.

MMcfe/d One MMcfe per day.

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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 s the fluids from one stratum will not escape into another or to the surface. Regulations of many stat require plugging of abandoned wells.

PUD Proved undeveloped.

pre-tax PV10% The present value of estimated future revenues to be generated from the produc 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 a 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) th 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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1,080,000 Shares

Whiting Petroleum Corporation

Common Stock

PROSPECTUS

Merrill Lynch & Co.

November 16, 2004