WHITING PETROLEUM CORP
Form 424A
November 05, 2004
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The information in this prospectus is not complete and may be changed. The selling stockholder may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities and it is not soliciting an offer to buy these securities in any state where the offer or sale is not permitted.

Filed Pursuant to Rule 424(a)

Registration No. 333-118261

Subject to Completion

Preliminary Prospectus Dated November 4, 2004

PROSPECTUS

1,080,000 Shares

Whiting Petroleum Corporation

Common Stock

Alliant Energy Resources, Inc., a wholly-owned subsidiary of Alliant Energy Corporation, is selling all of the shares offered hereby, all of which are currently outstanding.

Our common stock trades on the New York Stock Exchange under the symbol WLL. On November 3, 2004, the last sale price of our common stock as reported on the New York Stock Exchange was $29.85 per share.

Investing in our common stock involves risks that are described in the Risk Factors section beginning on page 16 of this prospectus.

	Per Share	Total
Public offering price	$	$
Underwriting discount	$	$
Proceeds, before expenses, to the selling stockholder	$	$

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The shares will be ready for delivery on or about , 2004.

Merrill Lynch & Co.

The date of this prospectus is , 2004.

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Unless the context otherwise requires, references in this prospectus to Whiting, we, us, our or ours refer to Whiting Petroleum Corporation, together with its operating subsidiaries. When the context requires, we refer to these entities separately. References in this prospectus to Resources refer to Alliant Energy Resources, Inc., a wholly-owned subsidiary of Alliant Energy Corporation. References in this prospectus to Alliant Energy refer to Alliant Energy Corporation.

You should rely only on the information contained in this prospectus. We have not, and the underwriters have not, authorized any other person to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. You should assume that the information appearing in this prospectus is accurate only as of the date on the front cover of this prospectus. Our business, financial condition, results of operations and prospects may have changed since that date.

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PROSPECTUS SUMMARY

This summary highlights selected information contained elsewhere in this prospectus. You should read this entire prospectus carefully, including Risk Factors and our financial statements and the notes to those financial statements included elsewhere in this prospectus. We have provided definitions for the oil and natural gas terms used in this prospectus in the Glossary of Oil and Natural Gas Terms included in this prospectus. The reserve information and other related operating statistics contained in this prospectus are as of January 1, 2004 unless otherwise indicated.

About Our Company

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

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

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

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

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

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

Core Area	Proved Reserves Oil (MMbbl)	Natural Gas (Bcf)	Total (Bcfe)	% Natural Gas	Pre-Tax PV10% Value (In millions)	October 2004 Average Daily Production (MMcfe)
Permian Basin	37.7	47.9	274.2	17.5%	$ 731.5	41.4
Rocky Mountains(1)	43.3	76.3	336.4	22.7%	$ 716.1	65.1
Gulf Coast	3.3	96.2	115.8	83.0%	$ 324.2	39.2
Michigan	1.9	87.8	99.1	88.6%	$ 219.1	21.0
Mid-Continent	2.0	15.7	27.9	56.4%	$ 61.8	6.2
California	0.0	14.0	14.0	100.0%	$ 35.2	4.9
Total	88.2	337.9	867.3	39.0%	$ 2,087.9	177.7

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

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

Total	88.2	337.9	867.3	39.0%	72%	$ 2,087.9	177.7

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

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

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

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

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

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

Permian Basin Properties

On September 23, 2004, we acquired interests in seventeen fields in the Permian Basin of West Texas and Southeast New Mexico, including interests in key fields such as Parkway Field in Eddy County, New Mexico; Would Have and Signal Peak Fields in Howard County, Texas; Keystone Field in Winkler County, Texas; and the DEB Field in Gaines County, Texas. The purchase price was $345.0 million in cash and was funded through borrowings under our bank credit agreement.

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

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

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

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

Equity Oil Company

We acquired 100% of the outstanding stock of Equity Oil Company on July 20, 2004. In the merger, we issued approximately 2.2 million shares of our common stock to Equity s shareholders and repaid all of Equity s outstanding debt of $29.0 million under its credit facility. Equity s operations are focused primarily in California, Colorado, North Dakota and Wyoming.

For the year ended December 31, 2003, Equity reported income from continuing operations of $2.4 million, net cash provided by operating activities of $11.5 million and production of 6.6 Bcfe (45% natural gas). As of

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October 1, 2004, Equity had 103.6 Bcfe of estimated proved reserves, of which 40.6% were natural gas and 69% were classified as proved developed, and had a pre-tax PV10% value of estimated proved reserves of approximately $217.6 million. The estimated October 2004 average daily production from these properties is approximately 16.1 MMcfe, implying an average reserve life of 17.6 years.

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

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

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

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

Other Cash Acquisitions of Properties

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

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

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

Business Strategy

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

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

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

Focusing on High Return Operated and Non Operated Properties. We have historically acquired operated as well as non operated properties that meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non operated property interests at attractive rates of return that provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non operated interests to the extent they meet our return criteria and further our growth strategy.

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

Competitive Strengths

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

Diversified Asset Base. As of January 1, 2004, we had interests in 5,006 wells in 16 states across our four core geographical areas of the United States. This property base, as well as our continuing business strategy of

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acquiring and developing properties in our core operating areas, presents us with a large number of opportunities for successful development and exploitation and additional acquisitions.

Experienced Management Team. Our management team averages 27 years of experience in the oil and natural gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, each of our acquisition professionals has at least 20 years of experience in the evaluation, acquisition and operational assimilation of oil and natural gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated detailed geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Our technical team has access to approximately 575 square miles of 3-D seismic data that we have assembled primarily over the past five years. A team with access to state of the art geophysical/ geological computer applications and hardware analyzes this information. Computer applications, such as the WellView® software system, enable us to quickly generate reports and schematics on our wells. In addition, our information systems enable us to update our production databases through daily uploads from hand held computers in the field. This technology and expertise has greatly aided our pursuit of attractive development projects.

Recent Developments

New Credit Agreement

On September 23, 2004, Whiting Oil and Gas Corporation entered into a new $750.0 million credit agreement with a syndicate of banks. The new credit agreement increased our borrowing base to $480.0 million from $195.0 million under our prior credit agreement. On September 23, 2004, we borrowed $400.0 million under the credit agreement to refinance the entire outstanding balance under the prior credit agreement and to fund our $345.0 million acquisition of oil and natural gas producing properties in the Permian Basin. For more information about our credit agreement, see Management s Discussion and Analysis of Financial Condition and Results of Operation Liquidity and Capital Resources Credit Facility.

Recent Drilling Activity

During the first nine months of 2004, we have invested $52.8 million of our $80.0 million development budget for 2004 for the drilling of 116 gross (49.7 net) wells with 108 successful completions and eight uneconomic wells, representing a 93% success rate. During the first nine months of 2004, our drilling activity has been primarily focused within our Northern Rocky Mountain and Gulf Coast core areas.

In South Texas, we have completed two successful Edwards wells in our Stuart City Reef Trend properties which are producing at a combined rate 5.9 MMcf per day. Also in this area, we completed three new Wilcox wells, which have a combined rate of 3.9 MMcf per day. Since June 30, 2004, production volumes in our Stuart City fields have increased by 62% to 14.6 MMcf per day.

In the Williston Basin, we have a new exploration program in western Billings County, North Dakota, targeting the Nisku Formation. Since June 30, 2004, we have drilled three new producing wells, which have a combined rate of 1,180 barrels of oil and 1.2 MMcf of natural gas per day as of October 11, 2004. We have an average 92.8% net revenue interest in these wells and we plan to drill five additional wells during 2004.

Corporate Information

Whiting Petroleum Corporation was incorporated in Delaware on July 18, 2003 for the sole purpose of becoming a holding company of Whiting Oil and Gas Corporation in connection with our initial public offering. Whiting Oil and Gas Corporation was incorporated in Delaware in 1983.

Our principal executive offices are located at 1700 Broadway, Suite 2300, Denver, Colorado 80290-2300, and our telephone number is (303) 837-1661.

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The Offering

Common stock offered by the selling stockholder	1,080,000 shares
Shares outstanding after the offering	28,600,347 shares
Concurrent offering by Whiting Petroleum Corporation	We are concurrently offering 7,500,000 shares of our common stock. The offering of our shares being made by Resources pursuant to this prospectus is not contingent on the successful completion of the offering of our shares being made by us. Accordingly, in making your investment decision, you should be aware that our offering of 7,500,000 shares may not be completed and that the anticipated use of proceeds from such offering cannot be assured.
Use of proceeds	We will not receive any proceeds from the sale of our shares by Resources.
Risk factors	Please read Risk Factors for a discussion of factors you should consider carefully before deciding to invest in shares of our common stock.
New York Stock Exchange symbol	WLL

The number of shares outstanding after the offering is based on 21,100,347 shares outstanding as of September 30, 2004 and assumes the successful completion of our concurrent offering of 7,500,000 shares of our common stock. This number assumes that the underwriters over-allotment option is not exercised. If the over-allotment option is exercised in full, we will issue and sell an additional 1,125,000 primary shares.

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. Resources is offering hereby all of the 1,080,000 shares of our common stock that it did not sell in our initial public offering and will own no shares of our common stock following this offering.

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Summary Historical and Unaudited Pro Forma Financial Information

The summary historical financial information for the year ended December 31, 2003 has been derived from our audited consolidated financial statements and related notes. The summary historical financial information for the nine months ended September 30, 2004 has been derived from our unaudited consolidated financial statements and related notes. This information is only a summary and you should read it in conjunction with material contained in Management s Discussion and Analysis of Financial Condition and Results of Operations, which includes a discussion of factors materially affecting the comparability of the information presented, and in conjunction with our financial statements and related notes included elsewhere in this prospectus. The unaudited interim period financial information, in our opinion, includes all adjustments, which are normal and recurring in nature, necessary for a fair presentation for 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.

The summary unaudited pro forma financial information for the year ended December 31, 2003 and the nine months ended September 30, 2004 has been derived from our unaudited pro forma financial statements and related notes included elsewhere in this prospectus. This information is only a summary and you should read it in conjunction with material contained in Unaudited Pro Forma Financial Statements and our historical financial statements and related notes included elsewhere in this prospectus. This summary unaudited pro forma financial information gives effect to our recent acquisition of Permian Basin properties as if such transaction had occurred as of January 1, 2003. This summary unaudited pro forma financial information does not reflect the pro forma effect of any of our other recent acquisitions, our concurrent primary offering of 7,500,000 shares of our common stock or the use of proceeds from our concurrent offering. Our historical results include the results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include results from our Wyoming and Utah acquisition that closed on September 30, 2004.

	Pro Forma for the Nine Months Ended September 30, 2004	Whiting Petroleum Corporation Nine Months Ended September 30, 2004	Pro Forma for the Year Ended December 31, 2003	Whiting Petroleum Corporation Year Ended December 31, 2003
	(in millions, except per share data)			
Consolidated Income Statement Information:				
Revenues:				
Oil and gas sales	$ 224.8	$ 166.4	$ 267.0	$ 175.8
Loss on oil and gas hedging activities	(3.6)	(3.6)	(8.7)	(8.7)
Gain on sale of oil and gas properties	1.0	1.0		
Gain on sale of marketable securities	4.7	4.7		
Interest income and other	0.2	0.2	0.3	0.3
Total revenues	$ 227.1	$ 168.7	$ 258.6	$ 167.4
Costs and expenses:				
Lease operating	$ 45.5	$ 34.6	$ 57.2	$ 43.2
Production taxes	13.6	10.2	15.9	10.7
Depreciation, depletion and amortization	48.5	34.5	67.2	41.3
Exploration and impairment	4.7	4.7	3.2	3.2
Phantom equity plan(1)			10.9	10.9
General and administrative	17.1	14.2	17.5	12.8
Interest expense	17.9	9.6	19.7	9.2
Total costs and expenses	$ 147.3	$ 107.8	191.6	$ 131.3
Income before income taxes and cumulative change in accounting principle	$ 79.8	$ 60.9	$ 67.0	$ 36.1
Income tax expense	(30.8)	(23.5)	(25.8)	(13.9)

Income from continuing operations	49.0	37.4	41.2	22.2
Cumulative change in accounting principle[(2)]			(3.9)	(3.9)
Net income	$ 49.0	$ 37.4	37.3	$ 18.3
Net income per common share from continuing operations, basic and diluted	$ 2.53	$ 1.93	$ 2.20	$ 1.18
Net income per common share, basic and diluted	$ 2.53	$ 1.93	$ 2.00	$ 0.98
Other Financial Information:				
EBITDA[(3)]	$ 146.2	$ 105.0	$ 150.0	$ 82.7

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(1) The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan, pursuant to which our employees received payments valued at $10.9 million in the form of shares of our common stock valued at approximately $6.5 million after withholding of shares for payroll and income taxes. As a result, in the fourth quarter of 2003, we recorded a one-time non-cash charge of $6.5 million and a one-time cash charge of $4.4 million, of which Alliant Energy Corporation funded the substantial majority. The phantom equity plan is now terminated.

(2) In 2003, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. The adoption of SFAS 143 included a one-time cumulative effect adjustment to net income.

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

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

	Pro Forma for The Nine Months Ended September 30, 2004	Whiting Petroleum Corporation Nine Months Ended September 30, 2004	Pro Forma for The Year Ended December 31, 2003	Whiting Petroleum Corporation Year Ended December 31, 2003
	(in millions)			
Net income	$ 49.0	$ 37.4	$ 37.3	$ 18.3
Income tax expense	30.8	23.5	25.8	13.9
Interest expense	17.9	9.6	19.7	9.2
Depreciation, depletion and amortization	48.5	34.5	67.2	41.3
EBITDA	$ 146.2	$ 105.0	$ 150.0	$ 82.7

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Summary Historical and Pro Forma Reserve and Operating Data

The following tables present summary information regarding our estimated net proved oil and natural gas reserves as of October 1, 2004 and as of December 31, 2003, and our historical operating data for the year ended December 31, 2003 and the nine months ended September 30, 2004. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC, and, except as otherwise indicated, give no effect to federal or state income taxes. For additional information regarding our reserves, please read Business and Properties Summary of Oil and Natural Gas Properties and Projects and note 10 to our financial statements. The summary pro forma reserve and operating data below gives effect to our recent acquisition of Permian Basin properties as if such transaction had occurred as of January 1, 2003. The summary unaudited pro forma reserve and operating data do not reflect the pro forma effect of our other recent acquisitions. Our historical operating data includes results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical operating data does not include results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our reserve data as of October 1, 2004 does include reserves from such acquisition.

	Whiting Petroleum Corporation as of October 1, 2004	Pro Forma as of December 31, 2003	Whiting Petroleum Corporation as of December 31, 2003
Reserve Data:			
Total estimated net proved reserves:			
Natural gas (Bcf)	337.9	287.6	231.0
Oil (MMbbls)	88.2	68.2	34.6
Total (Bcfe)	867.3	696.8	438.8
Estimated net proved developed reserves:			
Natural gas (Bcf)	245.8	212.7	171.9
Oil (MMbbls)	63.0	45.2	26.2
Total (Bcfe)	624.1	483.9	328.9
Estimated future net revenues before income taxes (in millions)	$ 3,908.0	$ 3,508.9	$ 1,352.2
Present value of estimated future net revenues before income taxes (in millions)[1][2]	$ 2,087.9	$ 1,142.1	$ 784.6
Standardized measure of discounted future net cash flows (in millions)[3]	$ 1,466.2	$ 896.1	$ 589.6

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	Pro Forma for the Nine Months Ended September 30, 2004	Whiting Petroleum Corporation Nine Months Ended September 30, 2004	Pro Forma for the Year Ended December 31, 2003	Whiting Petroleum Corporation Year Ended December 31, 2003
Operating Data:				
Net Production:				
Natural gas (Bcf)	20.6	17.1	27.4	21.6
Oil (MMbbls)	3.3	2.2	4.8	2.6
Total (Bcfe)	40.1	30.0	56.1	37.2
Net sales (in millions)(4):				
Natural gas	$ 107.4	$ 90.6	$ 130.4	$ 104.4
Oil	$ 117.4	$ 75.8	$ 136.6	$ 71.3
Total	$ 224.8	$ 166.4	$ 267.0	$ 175.7
Average sales price:				
Natural gas (per Mcf)(4)	$ 5.21	$ 5.30	$ 4.74	$ 4.78
Oil (per Bbl)(4)	$ 35.90	$ 35.13	$ 28.69	$ 27.50
Total (Mcfe)(4)	$ 5.59	$ 5.54	$ 4.76	$ 4.73
Average (per Mcfe):				
Lease operating expenses	$ 1.13	$ 1.15	$ 1.02	$ 1.16
Production taxes	$ 0.34	$ 0.34	$ 0.28	$ 0.29
Depreciation, depletion and amortization expenses	$ 1.20	$ 1.15	$ 1.20	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.42	$ 0.47	$ 0.31	$ 0.34
Net income	$ 1.22	$ 1.25	$ 0.67	$ 0.49
EBITDA(5)	$ 3.63	$ 3.49	$ 2.68	$ 2.22

(1) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, as of the calculation date, discounted at 10% per year on a pre-tax basis.

(2) The December 31, 2003 amount was calculated using a period end average realized oil price of $29.43 per barrel and a period end average realized natural gas price of $5.52 per Mcf, and the October 1, 2004 amount was calculated using a period end average realized oil price of $45.87 per barrel and a period end average realized natural gas price of $5.64 per Mcf.

(3) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10%.

(4) Before consideration of hedging transactions.

(5) See Note 3 to Summary Historical and Unaudited Pro Forma Financial Information for a definition of EBITDA and a reconciliation of EBITDA to net income for the periods presented.

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Summary Historical Financial Information

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

	Nine Months Ended September 30,		Year Ended December 31,		
	2004	2003	2003	2002	2001
	(dollars in millions)				
Consolidated Income Statement Information:					
Revenues:					
Oil and gas sales	$ 166.4	$ 133.6	$ 175.8	$ 122.7	$ 125.2
Gain (loss) on oil and gas hedging activities	(3.6)	(9.0)	(8.7)	(3.2)	2.3
Gain on sale of oil and gas properties	1.0			1.0	11.7
Gain on sale of marketable securities	4.7				
Interest income and other	0.2	0.2	0.3		0.2
Total revenues	$ 168.7	$ 124.8	$ 167.4	$ 120.5	$ 139.4
Costs and expenses:					
Lease operating	$ 34.6	$ 32.1	$ 43.2	$ 32.9	$ 29.8
Production taxes	10.2	8.1	10.7	7.4	6.5
Depreciation, depletion and amortization(1)	34.5	30.7	41.3	43.6	26.9
Exploration and impairment	4.7	1.0	3.2	1.8	0.8
Phantom equity plan(2)			10.9		
General and administrative	14.2	9.5	12.8	12.0	10.9
Interest expense	9.6	7.1	9.2	10.9	10.2
Total costs and expenses	$ 107.8	$ 88.5	$ 131.3	$ 108.6	$ 85.1
Income before income taxes and cumulative change in accounting principle	$ 60.9	$ 36.3	$ 36.1	$ 11.9	$ 54.3
Income tax expense(3)	(23.5)	(13.8)	(13.9)	(4.2)	(13.1)
Income from continuing operations	37.4	22.5	22.2	7.7	41.2
Cumulative change in accounting principle(4)		(3.9)	(3.9)		
Net income	$ 37.4	$ 18.6	$ 18.3	$ 7.7	$ 41.2
Net income per common share from continuing operations, basic and diluted	$ 1.93	$ 1.20	$ 1.18	$ 0.41	$ 2.20

Net income per common share, basic and diluted	$ 1.93	$ 0.99	$ 0.98	$ 0.41	$ 2.20
Other Financial Information:					
Net cash provided by operating activities	$ 96.9	$ 75.0	$ 96.4	$ 62.6	$ 62.3
Capital expenditures[5]	$ 498.1	$ 33.1	$ 52.0	$ 165.4	$ 99.6
EBITDA[6]	$ 105.0	$ 70.2	$ 82.6	$ 66.4	$ 91.4

	As of September 30,		As of December 31,		
	2004	2003	2003	2002	2001
	(dollars in millions)				
Balance Sheet Information:					
Cash and cash equivalents	$ 17.4	$ 42.5	$ 53.6	$ 4.8	$ 1.0
Total assets	$ 1,054.6	$ 502.5	$ 536.3	$ 448.5	$ 319.8
Long-term debt[7]	$ 538.8	$ 185.0	$ 188.0	$ 265.5	$ 163.6
Stockholders equity	$ 334.9	$ 224.9	$ 259.6	$ 122.8	$ 111.5

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

(2) The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan, pursuant to which our employees received payments valued at $10.9 million in the form of shares of our common stock valued at approximately $6.5 million after withholding of shares for payroll and income taxes. As a result, in the fourth quarter of 2003, we recorded a one-time non-cash charge of $6.5 million and a one-time cash charge of $4.4 million, of which Alliant Energy Corporation funded the substantial majority. The phantom equity plan is now terminated.

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

(4) In 2003, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. The adoption of SFAS 143 included a one-time cumulative effect adjustment to net income.

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

(6) See Note 6 to Selected Historical Financial Information for a definition of EBITDA and a reconciliation of EBITDA to net income for the periods presented.

(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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Summary Historical Reserve and Operating Data

The following tables present summary information regarding our estimated net proved oil and natural gas reserves as of October 1, 2004 and as of December 31, 2003, 2002 and 2001, and our historical operating data for the years ended December 31, 2003, 2002 and 2001 and the nine months ended September 30, 2004 and 2003. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the Securities and Exchange Commission, or the SEC, and, except as otherwise indicated, give no effect to federal or state income taxes. For additional information regarding our reserves, please read Business and Properties Summary of Oil and Natural Gas Properties and Projects and note 10 to our financial statements. Our historical operating data includes results from our recent acquisitions beginning on the following dates: Permian Basin, September 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical operating data does not include results from our Wyoming and Utah acquisition that closed on September 30, 2004, but our reserve data as of October 1, 2004 does include reserves from such acquisition.

	As of October 1,	As of December 31,		
	2004	2003	2002	2001
Reserve Data:				
Total estimated net proved reserves:				
Natural gas (Bcf)	337.9	231.0	236.0	227.5
Oil (MMbbls)	88.2	34.6	29.5	14.8
Total (Bcfe)	867.3	438.8	412.7	316.3
Estimated net proved developed reserves:				
Natural gas (Bcf)	245.8	171.9	167.6	136.8
Oil (MMbbls)	63.0	26.2	23.8	11.0
Total (Bcfe)	624.1	328.9	310.4	202.8
Estimated future net revenues before income taxes (in millions)	$ 3,908.0	$ 1,352.2	$ 1,112.4	$ 425.6
Present value of estimated future net revenues before income taxes (in millions)(1)(2)	$ 2,087.9	$ 784.6	$ 638.6	$ 244.6
Standardized measure of discounted future net cash flows (in millions)(3)	$ 1,466.2	$ 589.6	$ 476.0	$ 211.7

	Nine Months Ended September 30,		Year Ended December 31,		
	2004	2003	2003	2002	2001
Operating Data:					
Net Production:					
Natural gas (Bcf)	17.1	16.1	21.6	21.4	19.8
Oil (MMbbls)	2.2	1.9	2.6	2.3	2.1
Total (Bcfe)	30.0	27.7	37.2	35.2	32.4
Net sales (in millions)(4):					
Natural gas	$ 90.6	$ 80.1	$ 104.4	$ 68.6	$ 75.4
Oil	$ 75.8	$ 53.5	$ 71.3	$ 54.1	$ 49.8
Total	$ 166.4	$ 133.6	$ 175.7	$ 122.7	$ 125.2
Average sales price:					
Natural gas (per Mcf)(4)	$ 5.30	$ 4.98	$ 4.78	$ 3.21	$ 3.82
Oil (per Bbl)(4)	$ 35.13	$ 27.71	$ 27.50	$ 23.35	$ 23.85
Total (Mcfe)(4)	$ 5.54	$ 4.83	$ 4.73	$ 3.48	$ 3.88
Average (per Mcfe):					
Lease operating expenses	$ 1.15	$ 1.16	$ 1.16	$ 0.93	$ 0.92
Production taxes	$ 0.34	$ 0.29	$ 0.29	$ 0.21	$ 0.20
Depreciation, depletion and amortization expenses(5)	$ 1.15	$ 1.11	$ 1.11	$ 1.24	$ 1.11
General and administrative expenses, net of reimbursements	$ 0.47	$ 0.34	$ 0.34	$ 0.34	$ 0.34

Net income	$ 1.25	$ 0.67	$ 0.49	$ 0.22	$ 1.28
EBITDA[6]	$ 3.49	$ 2.54	$ 2.22	$ 1.88	$ 2.83

(1) The present value of estimated future net revenues attributable to our reserves was prepared using constant prices, as of the calculation date, discounted at 10% per year on a pre-tax basis.

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(2) The December 31, 2003 amount was calculated using a period end average realized oil price of $29.43 per barrel and a period end average realized natural gas price of $5.52 per Mcf, the December 31, 2002 amount was calculated using a period end average realized oil price of $28.21 per barrel and a period end average realized natural gas price of $4.39 per Mcf, and the October 1, 2004 amount was calculated using a period end average realized oil price of $45.87 per barrel and a period end average realized natural gas price of $5.64 per Mcf.

(3) The standardized measure of discounted future net cash flows represents the present value of future cash flows after income taxes discounted at 10%.

(4) Before consideration of hedging transactions.

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

(6) See Note 6 to Selected Historical Financial Information for a definition of EBITDA and a reconciliation of EBITDA to net income for the periods presented.

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RISK FACTORS

You should carefully consider each of the risks described below, together with all of the other information contained in this prospectus, before deciding to invest in shares of our common stock. If any of the following risks develop into actual events, our business, financial condition or results of operations could be materially adversely affected and you may lose all or part of your investment.

Risks Relating to the Oil and Natural Gas Industry and Our Business

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

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. These markets will likely continue to be volatile in the future. The prices we receive for our production, and the levels of our production, depend on numerous factors beyond our control. These factors include the following:

- changes in global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions, including embargoes, in or affecting other oil-producing activity;
- the level of global oil and natural gas exploration and production activity;
- the level of global oil and natural gas inventories;
- weather conditions;
- technological advances affecting energy consumption; and
- the price and availability of alternative fuels.

Lower oil and natural gas prices may not only decrease our revenues on a per unit basis but also may reduce the amount of oil and natural gas that we can produce economically. A substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined in the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders.

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

Our future success will depend on the success of our exploitation, exploration, development and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Please read Reserve estimates depend on many assumptions that may turn out to be inaccurate for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;

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- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and tropical storms;
- reductions in oil and natural gas prices;
- title problems; and
- limitations in the market for oil and natural gas.

Our acquisition activities may not be successful.

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

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

Substantial acquisitions or other transactions could require significant external capital and could change our risk and property profile.

In order to finance acquisitions of additional producing properties, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of production payments or other means. These changes in capitalization may significantly affect our risk profile. Additionally, significant acquisitions or other transactions can change the character of our operations and business. The character of the new properties may be substantially different in operating or geological characteristics or geographic location than our existing properties. Furthermore, we may not be able to obtain external funding for future acquisitions or other transactions or to obtain external funding on terms acceptable to us.

Properties that we buy may not produce as projected, and we may be unable to identify liabilities associated with the properties or obtain protection from sellers against them.

Our business strategy includes a continuing acquisition program and we have acquired a substantial number of properties in 2004. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

- the amount of recoverable reserves;
- future oil and natural gas prices;
- estimates of operating costs;

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- estimates of future development costs;
- estimates of the costs and timing of plugging and abandonment; and
- potential environmental and other liabilities.

Our assessment will not reveal all existing or potential problems, nor will it permit us to become familiar enough with the properties to assess fully their capabilities and deficiencies. In the course of our due diligence, we may not inspect every well, platform or pipeline. Inspections may not reveal structural and environmental problems, such as pipeline corrosion or groundwater contamination, when they are made. We may not be able to obtain contractual indemnities from the seller for liabilities that it created. We may be required to assume the risk of the physical condition of the properties in addition to the risk that the properties may not perform in accordance with our expectations.

If oil and natural gas prices decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

Accounting rules require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews, and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. We may incur impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Our leverage may impair our financial condition.

As of September 30, 2004, after giving effect to our offering of 7,500,000 shares of our common stock and the application of the proceeds of such offering to retire debt as if those transactions occurred on September 30, 2004, our total consolidated debt would have been $374.5 million. See Capitalization for additional information.

Our debt could have important consequences to you, including:

- increasing our vulnerability to general adverse economic and industry conditions;
- requiring a substantial portion of our cash flow from operations be used for the payment of interest on our debt, therefore reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions and general corporate requirements;
- limiting our ability to obtain additional financing to fund future working capital, capital expenditures, acquisitions and general corporate requirements;
- limiting our flexibility in planning for, or reacting to, changes in our business and the industries in which we operate; and

placing us at a competitive disadvantage to other less leveraged competitors.

Our development and exploration operations require substantial capital and we may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a loss of properties and a decline in our natural gas and oil reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration for and development, production and acquisition of oil and natural gas reserves. To date, we have financed capital expenditures primarily with bank borrowings and cash generated by operations. We intend to finance our future capital expenditures with cash flow from operations and our existing financing arrangements. Our cash flow from operations and access to capital are subject to a number of variables, including:

our proved reserves;

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the level of oil and natural gas we are able to produce from existing wells;

the prices at which oil and natural gas are sold; and

our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our bank credit agreement decreases as a result of lower oil and natural gas prices, operating difficulties, declines in reserves or for any other reason, then we may have limited ability to obtain the capital necessary to sustain our operations at current levels. We may, from time to time, need to seek additional financing. There can be no assurance as to the availability or terms of any additional financing.

If additional capital is needed, then we may not be able to obtain debt or equity financing on terms favorable to us, or at all. If cash generated by operations or available under our revolving credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could lead to a possible loss of properties and a decline in our natural gas and oil reserves.

Reserve estimates depend on many assumptions that may turn out to be inaccurate. Any material inaccuracies in these reserve estimates or underlying assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to economic factors. Any significant inaccuracies in these interpretations or assumptions could materially affect the estimated quantities and present value of reserves shown in this prospectus. Please read Business and Properties Summary of Oil and Natural Gas Properties and Projects for information about our oil and natural gas reserves.

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

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

You should not assume that the present value of future net revenues from our proved reserves referred to in this prospectus is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If natural gas prices decline by $0.10 per Mcf, then the pre-tax PV10% value of our proved reserves as of January 1, 2004 would decrease from $784.6 million to $773.2 million. If oil prices decline by $1.00 per barrel, then the pre-tax PV10% value of our proved reserves as of January 1, 2004 would decrease from $784.6 million to $770.0 million.

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

Oil and natural gas operations in the Rocky Mountains are adversely affected by seasonal weather conditions and lease stipulations designed to protect various wildlife. In certain areas drilling and other oil and natural gas activities can only be conducted during the spring and summer months. This limits our ability to

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operate in those areas and can intensify competition during those months for drilling rigs, oil field equipment, services, supplies and qualified personnel, which may lead to periodic shortages. Resulting shortages or high costs could delay our operations and materially increase our operating and capital costs.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities.

We describe some of our current prospects and our plans to explore those prospects in this prospectus. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. We cannot assure you that the analogies we draw from available data from other wells, more fully explored prospects or producing fields will be applicable to our drilling prospects.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations.

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

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

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

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

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

Our use of 3-D seismic data is subject to interpretation and may not accurately identify the presence of natural gas and oil, which could adversely affect the results of our drilling operations.

Even when properly used and interpreted, 3-D seismic data and visualization techniques are only tools used to assist geoscientists in identifying subsurface structures and hydrocarbon indicators and do not enable the interpreter to know whether hydrocarbons are, in fact, present in those structures. In addition, the use of 3-D seismic and other advanced technologies requires greater predrilling expenditures than traditional drilling strategies, and we could incur losses as a result of such expenditures. As a result, some of our drilling activities may not be successful or economical and our overall drilling success rate or our drilling success rate for activities in a particular area could decline. We often gather 3-D seismic over large areas. Our interpretation of seismic data delineates for us those portions of an area that we believe are desirable for drilling. Therefore, we may chose not to acquire option or lease rights prior to acquiring seismic data and, in many cases, we may identify hydrocarbon indicators before seeking option or lease rights in the location. If we are not able to lease those locations on acceptable terms, it would result in our having made substantial expenditures to acquire and analyze 3-D data without having an opportunity to attempt to benefit from those expenditures.

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

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends in substantial part on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could materially harm our business. We may be required to shut in wells for a lack of a market or because of inadequacy or unavailability of natural gas pipeline or gathering system capacity. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver to market.

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

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

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

taxation.

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

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Our operations may incur substantial liabilities to comply with the environmental laws and regulations.

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities, and concentration of materials that can be released into the environment in connection with drilling and production activities, limit or prohibit drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, and impose substantial liabilities for pollution resulting from our operations. Failure to comply with these laws and regulations may result in the assessment of administrative, civil, and criminal penalties, incurrence of investigatory or remedial obligations, or the imposition of injunctive relief. Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly material handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our results of operations, competitive position, or financial condition as well as those of the oil and natural gas industry in general. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or if our operations were standard in the industry at the time they were performed. Federal law and some state laws also allow the government to place a lien on real property for costs incurred by the government to address contamination on the property.

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

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

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

To a large extent, we depend on the services of our senior management and technical personnel. The loss of the services of our senior management or technical personnel, including James J. Volker, our President and Chief Executive Officer, James R. Casperson, our Chief Financial Officer, James T. Brown, our Vice President, Operations, John R. Hazlett, our Vice President, Acquisitions and Land or Mark R. Williams, our Vice President, Exploration and Development, could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals.

The unavailability or high cost of additional drilling rigs, equipment, supplies, personnel and oil field services could adversely affect our ability to execute on a timely basis our exploration and development plans within our budget.

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

Competition in the oil and natural gas industry is intense, which may adversely affect our ability to compete.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Many of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital.

Our use of oil and natural gas price hedging contracts involves credit risk and may limit future revenues from price increases and result in significant fluctuations in our net income.

We enter into hedging transactions for our oil and natural gas production to reduce our exposure to fluctuations in the price of oil and natural gas. Our hedging transactions have to date consisted of financially settled crude oil and natural gas forward sales contracts with major financial institutions. We have contracts maturing in the fourth quarter of 2004 covering the sale of 1,450,000 MMbtu of natural gas and 314,000 barrels of oil, and our amended and restated credit agreement requires us to hedge at least 60% of our total forecasted PDP production for the period from November 1, 2004 through December 31, 2005. See Management s Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosure about Market Risk for pricing and a more detailed discussion of our hedging transactions.

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

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 are currently pursuing a primary offering of 7,500,000 shares of our common stock. Assuming an offering price of $29.85 per share, we would expect to receive net proceeds of approximately $ 214.3 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 primary 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 contingent 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 decline. 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 the operating performance of particular companies. These broad market fluctuations may adversely affect 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. We currently intend to retain future earnings, if any, to finance the expansion of our business. Our future dividend policy is within the discretion of our board of directors and will depend upon various factors, including our 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 stock.

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, board 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, Delaware 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 Preferred 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 historical facts, including, without limitation, statements regarding our future financial position, business strategy, projected revenues, earnings, costs, capital expenditures and debt levels, and plans and objectives of management for future operations, are forward looking statements. When used in this prospectus, words such as we expect, intend, plan, estimate, anticipate, belie should or the negative thereof or variations thereon or similar terminology are generally intended to identify forward looking statements. Such forward looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. Some, but not all, of the risks and uncertainties include: declines in oil or natural gas prices; our level of success in exploitation, exploration, development and production activities; 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 natural gas industry; risks arising out of our hedging transactions; and other risks described under the caption Risk Factors . We assume no obligation, and disclaim any duty, to update the forward looking statements in this 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 an assumed offering price of $29.85 per share, after deducting the underwriting discount and estimated offering expenses, and the 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 Adjusted
	(dollars in thousands)	
Cash and cash equivalents	$ 17,361	$ 17,361
Short-term debt	$ 50,000	$
Long-term debt:		
Whiting Oil and Gas Corporation credit agreement	385,000	220,655
Note payable to Alliant Energy Corporation	3,130	3,130
Senior subordinated notes[(1)]	150,697	150,697
Total debt	588,827	374,482
Stockholders equity:		
Common stock: $0.001 par value, 75,000,000 shares authorized, 21,100,347 shares issued and outstanding	21	29
Preferred Stock: $0.001 par value, 5,000,000 shares authorized, no shares issued or outstanding		
Additional paid-in capital	216,120	430,457
Deferred compensation	(2,035)	(2,035)
Accumulated other comprehensive loss	(6,050)	(6,050)
Retained earnings	126,841	126,841
Total stockholders equity	$ 334,897	$ 549,242
Total capitalization	$ 923,724	$ 923,724

(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 since 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	Low
Fiscal Year Ended December 31, 2003		
Fourth Quarter (from November 20, 2003 through December 31, 2003)	$ 18.54	$ 16.15
Fiscal Year Ended December 31, 2004		
First Quarter (Ended March 31, 2004)	$ 23.94	$ 18.45
Second Quarter (Ended June 30, 2004)	$ 27.59	$ 21.50
Third Quarter (Ended September 30, 2004)	$ 31.20	$ 21.85
Fourth Quarter (Through November 3, 2004)	$ 34.22	$ 29.00

On November 3, 2004, the last sale price of our common stock as reported on the New York Stock Exchange was $29.85.

As of October 14, 2004, there were 996 stockholders of record and approximately 16,000 beneficial 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 is within the discretion of our board of directors and will depend upon various factors, including our results of operations, financial condition, capital requirements and investment opportunities. In addition, the agreements governing our indebtedness prohibit us from paying dividends.

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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 as 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 23, 2004; Equity Oil Company, July 20, 2004; Colorado and Wyoming, August 13, 2004; and Louisiana and Texas, August 16, 2004. Our historical results do not include results from our Wyoming and Utah acquisition that closed on September 30, 2004. A pro forma balance sheet has not been presented since the acquisition has been reflected in the September 30, 2004 balance sheet of Whiting Petroleum Corporation included elsewhere in this prospectus. The unaudited pro forma statement of operations for the nine months ended September 30, 2004 and for the year ended December 31, 2003 was prepared as if the acquisition had occurred at January 1, 2003.

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

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

The following unaudited pro forma financial statements do not purport to represent what our results of operations would have been if this acquisition had occurred on January 1, 2003. These unaudited pro forma financial statements should be read in conjunction with our historical financial statements and related notes for the periods presented 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 Forma Combined September 30, 2004
REVENUES				
Oil and gas sales	$ 166.4	$ 39.1	$ 19.3	$ 224.8
Loss on oil and gas hedging activities	(3.6)			(3.6)
Gain on sale of marketable securities	4.7			4.7
Gain on sale of oil and gas properties	1.0			1.0
Interest income and other	0.2			0.2
Total revenues	168.7	39.1	19.3	227.1
COSTS AND EXPENSES:				
Lease operating	34.6	8.3	2.6	45.5
Production taxes	10.2	2.3	1.1	13.6
Depreciation, depletion and amortization	34.5		14.0	48.5
Exploration and impairment	4.7			4.7
General and administrative	14.2		2.9	17.1
Interest expense	9.6		8.3	17.9
Total costs and expenses	$ 107.8	10.6	28.9	147.3
INCOME BEFORE INCOME TAXES	60.9	$ 28.5	(9.6)	79.8
INCOME TAX EXPENSE:				
Current	(0.4)			(0.4)
Deferred	(23.1)		(7.3)	(30.4)
Total income tax expenses	(23.5)		(7.3)	(30.8)
NET INCOME	$ 37.4		$ (16.9)	$ 49.0
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 1.93			$ 2.53
WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC	19,341			19,341

WEIGHTED AVERAGE SHARES OUTSTANDING, DILUTED	19,370	19,370

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 Forma Combined December 31, 2003
REVENUES				
Oil and gas sales	$ 175.8	$ 91.2	$	$ 267.0
Loss on oil and gas hedging activities	(8.7)			(8.7)
Interest income and other	0.3			0.3
Total revenues	167.4	91.2		258.6
COSTS AND EXPENSES:				
Lease operating	43.2	14.0		57.2
Production taxes	10.7	5.2		15.9
Depreciation, depletion and amortization	41.3		25.9	67.2
Exploration	3.2			3.2
General and administrative	12.8		4.7	17.5
Phantom equity plan	10.9			10.9
Interest expense	9.2		10.5	19.7
Total costs and expenses	131.3	19.2	41.1	191.6
INCOME BEFORE INCOME TAXES AND CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	36.1	$ 72.0	(41.1)	67.0
INCOME TAX EXPENSE:				
Current	(2.4)			(2.4)
Deferred	(11.5)		(11.9)	(23.4)
Total income tax expense	(13.9)		(11.9)	(25.8)
INCOME FROM CONTINUING OPERATIONS	22.2		(53.0)	41.2
CUMULATIVE CHANGE IN ACCOUNTING PRINCIPLE	(3.9)			(3.9)
NET INCOME	$ 18.3		$ (53.0)	$ 37.3
Earnings per share from continuing operations, basic and diluted	$ 1.18			$ 2.20
Cumulative change in accounting principle	(0.20)			(0.20)
NET INCOME PER COMMON SHARE, BASIC AND DILUTED	$ 0.98			$ 2.00

WEIGHTED AVERAGE SHARES OUTSTANDING, BASIC AND DILUTED	18,750	18,750

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NOTES TO THE UNAUDITED PRO FORMA STATEMENTS OF OPERATIONS

1. BASIS OF PRESENTATION

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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

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SELECTED HISTORICAL FINANCIAL INFORMATION

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

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

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

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

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

(2) The completion of our initial public offering in November 2003 constituted a triggering event under our phantom equity plan, pursuant to which our employees received payments valued at $10.9 million in the form of shares of our common stock valued at approximately $6.5 million after withholding of shares for payroll and income taxes. As a result, in the fourth quarter of 2003, we recorded a one-time non-cash charge of $6.5 million and a one-time cash charge of $4.4 million, of which Alliant Energy Corporation funded the substantial majority. The phantom equity plan is now terminated.

(3) We generated Section 29 tax credits of $3.0 million in 1999, $5.2 million in 2000, $6.6 million in 2001 and $5.4 million in 2002. Section 29 tax credit provisions of the Internal Revenue Code expired as of December 31, 2002. In 2002, we were able to use our $5.4 million of Section 29 tax credits in the consolidated federal income tax return filed by Alliant Energy, but since these credits would not have been used in a stand-alone filing, they were recorded as additional paid-in capital as opposed to a reduction in income tax expense.

(4) In 2003, we adopted Statement of Financial Accounting Standards No. 143, Accounting for Asset Retirement Obligations. The adoption of SFAS 143 included a one-time cumulative effect adjustment to net income.

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

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

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

	Nine Months	Year Ended December 31,

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

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

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MANAGEMENT S DISCUSSION AND

ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Introduction

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

Overview

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

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

We have historically acquired operated as well as non-operated properties that meet or exceed our rate of return criteria. For acquisitions of properties with additional development, exploitation and exploration potential, our focus has been on acquiring operated properties so that we can better control the timing and implementation of capital spending. In some instances, we have been able to acquire non-operated property interests at attractive rates of return that provided a foothold in a new area of interest or complemented our existing operations. We intend to continue to acquire both operated and non-operated interests to the extent we believe they meet our return criteria. In addition, our willingness to acquire non-operated properties in new geographic regions provides us with geophysical and geologic data in some cases that leads to further acquisitions in the same region, whether on an operated or non-operated basis. We sell properties when management is of the opinion that the sale price realized will provide an above average rate of return for the property or when the property no longer matches the profile of properties we desire to own.

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

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

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

Results of Operations

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

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

(1) Before consideration of hedging transactions.

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

Oil and Natural Gas Sales. Our oil and natural gas sales revenue increased approximately $32.8 million to $166.4 million for the first nine months of 2004. Sales are a function of sales volumes and average sales prices. Our sales volumes increased 8.6% between periods on a Mcfe basis. The volume increase resulted from successful drilling and acquisition activities over the past year that produced new sales volumes that more than offset natural decline. Our average price for natural gas sales increased 6.4% and our average price for crude oil increased 26.8% between periods.

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

Gain on Sale of Marketable Securities. During the initial nine months of 2004, we sold all of our holdings in Delta Petroleum, Inc., which trades publicly under the symbol DPTR . We realized gross proceeds of $5.4 million and recognized a gain on sale of $4.8 million. At September 30, 2004, we had no investments in marketable securities.

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

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Lease Operating Expenses. Our lease operating expenses per Mcfe decreased from $1.16 during the first nine months of 2003 to $1.15 during the same period in 2004. The decrease was less than 1%, which represented improved operating efficiency more than offsetting price inflation caused by increased demand for goods and services in the industry.

Production Taxes. The production taxes we pay are generally calculated as a percentage of oil and natural gas sales revenue before the effects of hedging. We take full advantage of all credits and exemptions allowed in the various taxing jurisdictions. Due to our broad asset base, we expect our production tax rate to vary between 6.0% to 6.5% of oil and natural gas sales revenue. Our production taxes for the initial nine months of 2004 and 2003 were 6.1% of oil and natural gas sales.

Depreciation, Depletion and Amortization. Depreciation, depletion and amortization expense (DD&A) increased $3.8 million to $34.5 million for the first nine months of 2004. The increase resulted from increased production and an increase in the DD&A rate. On a Mcfe basis, the rate increased from $1.11 during the first nine months of 2003 to $1.15 during the same period in 2004. We expect our DD&A rate to increase in the fourth quarter due to the effects of the recent acquisitions. Changes to the pricing environment can also impact our DD&A rate. Price increases allow for longer economic production lives and corresponding increased reserve volumes and, as a result, lower depletion rates. Price decreases have the opposite effect. The components of our depreciation, depletion and amortization expense were as follows (in thousands):

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

Exploration and Impairment Costs. Our exploration and impairment costs increased $3.7 million to $4.7 million for the first nine months of 2004. The higher exploratory costs were related to our increased purchases of seismic in 2004 to support our increased drilling budget. The impairment charge represents the write down of cost associated with the High Island field located off the coast of Texas.

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

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

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

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

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

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

The decrease in bank interest was primarily due to our $40.0 million pay down of our credit facility on February 17, 2004 and our repayment of the remaining principal balance outstanding under the credit facility on May 11, 2004 with the proceeds from the issuance of our 7 1/4% Senior Subordinated Notes due 2012. We expect our overall interest expense to increase during the remainder of 2004 due to the cash acquisitions closed during the third quarter of 2004, which increased the outstanding balance under our credit facility to $435 million as of September 30, 2004. In addition, in August, we entered into an interest rate swap causing the interest rate on $75 million of the 7 1/4% Senior Subordinated Notes due 2012 to change from a 7.25% fixed rate to a floating rate. The effect of the swap was to lower our overall effective interest rate on this debt from 7.25% to approximately 5.6% through November 1, 2004. On November 1, 2004 and every six months thereafter, the floating rate component will be locked in for six month periods at the then in effect six month London Interbank Offered Rate, or LIBOR, rate plus a margin of 2.345%. The decrease in interest expense related to Alliant was due to the March 31, 2003 conversion of $80.9 million of intercompany debt into our equity. The accretion of our tax sharing liability is related to a step-up in tax basis effected immediately prior to our initial public offering (IPO) in November 2003. A further explanation of the step-up transaction is included in the Liquidity and Capital Resources section below.

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

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

Net Income. Net income increased from $18.6 million during the initial nine months of 2003 to $37.4 million during the same period in 2004. The primary reasons for this increase included 20% higher crude oil and natural gas prices net of hedging between periods, 8.6% increase in equivalent volumes sold, the impact of the cumulative effect of adoption of SFAS No. 143 in 2003, the impact of property and marketable security sales in 2004, offset by higher lease operating expense, general and administrative, DD&A, interest and exploration and impairment costs in 2004.

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

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

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

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

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

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

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

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

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

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

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

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

Cumulative Change in Accounting Principle. Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived assets and requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. This statement applies directly to plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated useful lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 7%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million).

Net Income. Net income increased from $7.7 million in 2002 to $18.3 million in 2003. The primary reasons for this increase included higher crude oil and natural gas prices between periods and higher volumes sold, offset by higher lease operating, tax and general and administrative costs due to our growth.

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

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

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

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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 hedging loss of $3.0 million, and 17% of our oil volumes during 2001, incurring a gain of $0.7 million.

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

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

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

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

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

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

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

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

Net Income. Net income decreased from $41.2 million in 2001 to $7.7 million in 2002. The primary reasons were a $19.0 million decline in revenues, a $23.5 million increase in expenses and the inability to recognize $5.4 million of tax credits as a reduction of tax expense. The revenue decrease was caused by a decline in oil and natural gas prices between years and $10.7 million less gains from the sales of properties in 2002. The expense increase was caused by the $9.0 million reduction to 2001 depreciation, depletion and amortization related to the adjustment of the Point Arguello asset retirement obligations and cost increases in all other categories to operate and administer the property acquisitions during 2001 and 2002.

Liquidity and Capital Resources

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

We continually evaluate our capital needs and compare them to our capital resources. Our budgeted capital expenditures for the further development of our property base are $80.0 million during 2004, an increase from the $40.3 million spent on capitalized development during 2003. During the first nine months of 2004, we spent $52.8 million on development, which was a 102% increase from the $26.2 million spent on development during the first nine months of 2003. We also spent $445.3 million on acquisitions, funded primarily by borrowings under our credit facility, all in the third quarter of 2004. Although we have no specific budget for property acquisitions, we will continue to seek property acquisition opportunities that complement our existing core property base. We expect to fund the remainder of our 2004 development expenditures from internally generated cash flow and cash on hand. We believe that should attractive acquisition opportunities arise or development expenditures exceed $80.0 million, we could finance the additional capital expenditures with cash on hand, operating cash flow, borrowings under Whiting Oil and Gas Corporation s credit agreement, issuances of additional equity or development with industry partners. Our level of capital expenditures is largely discretionary, and the amount of funds devoted to any particular activity may increase or decrease significantly depending on available opportunities, commodity prices, cash flows and development results, among other factors.

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

The credit agreement provides for interest only payments until September 23, 2008, when the entire amount borrowed is due. In addition, the credit agreement provides that Whiting Oil and Gas Corporation will make principal payments under the credit agreement by May 1, 2005 to reduce the principal balance to $385.0 million. Whiting Oil and Gas Corporation may, throughout the four year term of the credit agreement, borrow, repay and reborrow up to the borrowing base in effect from time to time. Interest accrues, at our option, at either (1) the base rate plus a margin where the base rate is defined as the higher of the federal funds rate plus 0.5% or the prime rate and the margin varies from 0% to 0.50% depending on the utilization percentage of the borrowing base, or (2) at the LIBOR rate plus a margin where the margin varies from 1.00% to 1.75% depending on the utilization percentage of the borrowing base. We have consistently chosen the LIBOR rate option since it delivers the lowest effective interest rate. Commitment fees of 0.250% to 0.375% accrue on the unused portion of the borrowing base, depending on the utilization percentage, and are included as a component of interest expense.

The credit agreement contains restrictive covenants that may limit our ability to, among other things, pay cash dividends, incur additional indebtedness, sell assets, make loans to others, make investments, enter into mergers, change material contracts, incur liens and engage in certain other transactions without the prior consent of the lenders and requires us to maintain a debt to EBITDAX (as defined in the credit agreement) ratio of less than 3.5 to 1 and a working capital ratio of greater than 1 to 1. The credit agreement also requires us to hedge at least 60%, but not more than 75%, of our total forecasted PDP production for the period November 1, 2004 through December 31, 2005 in the form of costless collars or fixed price swaps, with a minimum floor price of $35 per barrel of oil or $4.50 per MMbtu. After December 31, 2005, the credit agreement will not require us to hedge any of our production, but will continue to limit our hedging to a maximum of 75% of our forecasted PDP production. In addition, while the credit agreement allows our subsidiaries to make payments to us so that we may pay interest on our senior subordinated notes, it does not allow our subsidiaries to make payments to us to pay principal on the senior subordinated notes. We were in compliance with our covenants under the credit agreement as of September 30, 2004. The credit agreement is secured by a first lien on substantially all of Whiting Oil and Gas Corporation s assets. Whiting Petroleum Corporation and Equity Oil Company have guaranteed the obligations of Whiting Oil and Gas Corporation under the credit agreement, Whiting Petroleum Corporation has pledged the stock of Whiting Oil and Gas Corporation and Equity Oil Company as security for its guarantee and Equity Oil Company has mortgaged substantially all of its assets as security for its guarantee.

7 1/4% Senior Subordinated Notes due 2012. On May 11, 2004, we issued, in a private placement, $150.0 million aggregate principal amount of our 7 1/4% senior subordinated notes due 2012. The net proceeds of the offering were used to retire all of our debt outstanding under Whiting Oil and Gas Corporation s credit agreement. The notes were issued at 99.26% of par and the associated discount is being amortized to interest expense over the term of the notes. On July 12, 2004, we completed an exchange offer in which we issued $150.0 million aggregate principal amount of new 7 1/4% senior subordinated notes due 2012 registered under the Securities Act of 1933 in exchange for the old notes. The notes are unsecured obligations of ours and are subordinated to all of our senior debt. The indenture governing the notes contains restrictive covenants that may limit our and our subsidiaries ability to, among other things, pay cash dividends, redeem or repurchase our capital stock or our subordinated debt, make investments, incur additional indebtedness or issue preferred stock, sell assets, consolidate, merge or transfer all or substantially all of the assets of us and our restricted subsidiaries taken as a whole and enter into hedging contracts. These covenants may limit the discretion of our management in operating our business. We were in compliance with these covenants as of September 30, 2004. Three of our subsidiaries, Whiting Oil and Gas Corporation, Whiting Programs, Inc. and Equity Oil Company, have fully, unconditionally, jointly and severally guaranteed our obligations under the notes.

Alliant Energy Promissory Note. In conjunction with our initial public offering in November 2003, we issued a promissory note payable to Alliant Energy in the aggregate principal amount of $3.0 million. The note bears interest at an annual rate of 5%. All principal and interest on the promissory note are due on November 25, 2005.

Tax Separation and Indemnification Agreement with Alliant Energy. In connection with our initial public offering in November 2003, we entered into a tax separation and indemnification agreement with Alliant Energy. Pursuant to this agreement, we and Alliant Energy made a tax election with the effect that the tax basis of the assets of Whiting Oil and Gas Corporation and its subsidiaries were increased to the deemed purchase price of their assets immediately prior to such initial public offering. We have adjusted deferred taxes on our balance sheet to reflect the new tax basis of our assets. This additional basis is expected to result in increased future income tax deductions and, accordingly, may reduce income taxes otherwise payable by us. Under this agreement, we have agreed to pay to Alliant Energy 90% of the future tax benefits we realize annually as a result of this step up in tax basis for the years ending on or prior to December 31, 2013. Such tax benefits will generally be calculated by comparing our actual taxes to the taxes that would have been owed by us had the increase in basis not occurred. In 2014, we will be obligated to pay Alliant Energy the present value of the remaining tax benefits assuming all such tax benefits will be realized in future years. The initial recording of this transaction in November 2003 resulted in a $57.2 million increase in deferred tax assets, a $28.6 million discounted payable to Alliant Energy and a $28.6 million increase to stockholders equity.

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Schedule of Contractual Obligations. The following table summarizes our obligations and commitments as of September 30, 2004 to make future payments under certain contracts, aggregated by category of contractual obligation, for specified time periods. This table does not include asset retirement obligations or production participation plan liabilities since we cannot determine with accuracy the timing of future payments. This table also does not include interest expense since we cannot determine with accuracy the timing of future loan advances and repayments and the future interest rate to be charged under floating rate instruments. During August 2004, we entered into an interest rate swap on $75.0 million of our $150.0 million fixed rate 7 1/4% senior subordinated notes due 2012. The amount of interest we expect to pay relating to the $75.0 million of our senior subordinated notes remaining under the 7 1/4% fixed rate is $1.4 million during the last three months of 2004, then $5.4 million annually through the term of the notes.

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

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

Off-Balance Sheet Arrangements. As part of a 2002 purchase transaction, we agreed to share with the seller 50% of the actual price received for certain crude oil production in excess of $19.00 per barrel. The agreement runs through December 31, 2009 and contains a 2% price escalation per year. As a result, the sharing amount at January 1, 2004 increased to 50% of the actual price received in excess of $19.77 per barrel. As of September 30, 2004, approximately 45,800 net barrels of crude oil per month (10% of October 2004 estimated net crude oil production) are subject to this sharing agreement. The terms of the agreement do not provide for a maximum amount to be paid. As of September 30, 2004, we have paid $6.1 million under this agreement and we have accrued an additional $427,000 as currently payable.

New Accounting Policies

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

Effective January 1, 2003, we adopted the provisions of SFAS No. 143, Accounting for Asset Retirement Obligations. This statement generally applies to legal obligations associated with the retirement of long-lived

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assets that result from the acquisition, construction, development and/or the normal operation of a long-lived asset. SFAS No. 143 requires us to recognize the fair value of asset retirement obligations in our financial statements by capitalizing that cost as a part of the cost of the related asset. In regards to us, this statement applies directly to the plug and abandonment liabilities associated with our net working interest in well bores. The additional carrying amount is depleted over the estimated lives of the properties. The discounted liability is based on historical abandonment costs in specific areas and is accreted at the end of each accounting period through charges to accretion expense. The liability is discounted using a credit-adjusted risk-free rate of approximately 7%. If the obligation is settled for other than the carrying amount, a gain or loss is recognized on settlement. Upon adoption of SFAS No. 143, we recorded an increase to our discounted asset retirement obligations of $16.4 million, increased proved property cost by $10.1 million and recognized a one-time cumulative effect charge of $3.9 million (net of a deferred tax benefit of $2.4 million). We have an additional $4.3 million asset retirement obligations relating to our retained obligation with respect to the Point Arguello facility located offshore from California.

FASB Interpretation No. 45, or FIN 45, Guarantor s Accounting and Disclosure Requirements for Guarantees, Including Indirect Guarantees of Indebtedness of Others was issued in November 2002 by the FASB. FIN 45 requires a guarantor to recognize a liabil