WHITING PETROLEUM CORP
Form 424B5
January 26, 2009

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The information in this prospectus supplement and the accompanying prospectus is not complete and may be changed. This prospectus supplement and the accompanying prospectus are not an offer to sell these securities and are not soliciting an offer to buy these securities in any jurisdiction where this offer or sale is not permitted.

Filed Pursuant to Rule 424(b)(5)
Registration File No. 333-133889

Subject to Completion
Preliminary Prospectus Supplement dated January 26, 2009

PROSPECTUS SUPPLEMENT
(To prospectus dated May 8, 2006)

8,000,000 Shares

Whiting Petroleum Corporation

Common Stock

We are offering 8,000,000 shares of our common stock. Our common stock is traded on the New York Stock Exchange under the symbol WLL. On January 23, 2009, the last sale price of our common stock as reported on the New York Stock Exchange was $33.94 per share.

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

	Per Share	Total
Public offering price	$	$
Underwriting discount	$	$
Proceeds, before expenses, to us	$	$

The underwriters may also purchase up to an additional 1,200,000 shares from us at the public offering price, less the underwriting discount, within 30 days from the date of this prospectus supplement to cover overallotments.

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

The shares will be ready for delivery on or about , 2009.

Book-Running Manager

Merrill Lynch & Co.

J.P. Morgan		**Raymond James**
Barclays Capital	**KeyBanc Capital Markets**	**Wachovia Securities**
Jefferies & Company	**RBC Capital Markets**	**Tristone Capital**

The date of this prospectus supplement is , 2009.

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Prospectus Supplement

Prospectus

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ABOUT THIS PROSPECTUS SUPPLEMENT

This document is in two parts. The first part is this prospectus supplement, which describes the specific terms of this offering. The second part, the accompanying prospectus, gives more general information, some of which may not apply to this offering. You should read the entire prospectus supplement, as well as the accompanying prospectus and the documents incorporated by reference that are described under Where You Can Find More Information in this prospectus supplement and the accompanying prospectus. In the event that the description of this offering varies between this prospectus supplement and the accompanying prospectus, you should rely on the information contained in this prospectus supplement.

You should rely only on the information contained in this prospectus supplement and the accompanying 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 supplement and the accompanying prospectus is accurate only as of the date on their respective front covers. Our business, financial condition, results of operations and prospects may have changed since those dates.

In this prospectus supplement, we, us, our or ours refer to Whiting Petroleum Corporation and its consolidated subsidiaries.

GLOSSARY OF CERTAIN OIL AND GAS TERMS

We have included below the definitions for certain oil and gas terms used in this prospectus supplement:

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

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

Bcf One billion cubic feet of natural gas.

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

BOE/d One BOE per day.

CO_2 flood A tertiary recovery method in which CO_2 is injected into a reservoir to enhance hydrocarbon recovery.

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

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

MBOE One thousand BOE.

MBOE/d One MBOE per day.

Mcf One thousand cubic feet of natural gas.

MMBbl One million Bbl.

MMBOE One million BOE.

MMBtu One million British Thermal Units.

MMcf One million cubic feet of natural gas.

MMcf/d One MMcf per day.

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net revenue interest The interest owned in the revenues of a crude oil and natural gas property, after all royalties, overriding royalties and other burdens have been deducted from the working interest.

plugging and abandonment Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids from one stratum will not escape into another or to the surface. Regulations of many states require plugging of abandoned wells.

pre-tax PV10% The present value of estimated future revenues to be generated from the production of proved reserves calculated in accordance with the guidelines of the Securities and Exchange Commission, or the SEC, net of estimated lease operating expense, production taxes and future development costs, using price and costs as of the date of estimation without future escalation, without giving effect to non-property related expenses such as general and administrative expenses, debt service and depreciation, depletion and amortization, or Federal income taxes and discounted using an annual discount rate of 10%.

reservoir A porous and permeable underground formation containing a natural accumulation of producible oil and/or natural gas that is confined by impermeable rock or water barriers and is individual and separate from other reservoirs.

resource play Refers to drilling programs targeted at regionally distributed oil or natural gas accumulations. Successful exploitation of these reservoirs is dependent upon new technologies such as horizontal drilling and multi-stage fracture stimulation to access large rock volumes in order to produce economic quantities of oil or natural gas.

working interest The interest in a crude oil and natural gas property (normally a leasehold interest) that gives the owner the right to drill, produce and conduct operations on the property and a share of production, subject to all royalties, overriding royalties and other burdens and to all costs of exploration, development and operations and all risks in connection therewith.

SPECIAL NOTE REGARDING FORWARD-LOOKING STATEMENTS

This prospectus supplement, the accompanying prospectus and the documents incorporated by reference contain 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 supplement, the accompanying prospectus and the documents incorporated by reference, words such as we expect, intend, plan, estimate, anticipate, believe or should or the negative thereof or variations thereon or terminology are generally intended to identify forward-looking statements. Such forward-looking statements are subject to risks and uncertainties that could cause actual results to differ materially from those expressed in, or implied by, such statements. These risks and uncertainties include, but are not limited to:

- declines in oil or natural gas prices;
- impacts of the global financial crisis;
- our level of success in exploitation, exploration, development and production activities;
- adverse weather conditions that may negatively impact development or production activities;

the timing of our exploration and development expenditures, including our ability to obtain drilling rigs and CO_2;

inaccuracies of our reserve estimates or our assumptions underlying them;

revisions to reserve estimates as a result of changes in commodity prices;

risks related to our level of indebtedness and periodic redeterminations of Whiting Oil and Gas Corporation s borrowing base under our credit agreement;

our ability to generate sufficient cash flows from operations to meet the internally funded portion of our capital expenditures budget;

our ability to obtain external capital to finance exploration and development operations and acquisitions;

our ability to identify and complete acquisitions and to successfully integrate acquired businesses;

unforeseen underperformance of or liabilities associated with acquired properties;

our ability to successfully complete potential asset dispositions;

failure of our properties to yield oil or gas in commercially viable quantities;

uninsured or underinsured losses resulting from our oil and gas operations;

our inability to access oil and gas markets due to market conditions or operational impediments;

the impact and costs of compliance with laws and regulations governing our oil and gas operations;

our ability to replace our oil and natural gas reserves;

any loss of our senior management or technical personnel;

competition in the oil and gas industry in the regions in which we operate;

risks arising out of our hedging transactions; and

other risks described under the caption Risk Factors.

We assume no obligation, and disclaim any duty, to update the forward-looking statements in this prospectus supplement, the accompanying prospectus or the documents we incorporate by reference. We urge you to carefully review and consider the disclosures made in this prospectus supplement, the accompanying prospectus and our reports filed with the SEC and incorporated by reference herein that attempt to advise interested parties of the risks and factors that may affect our business.

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PROSPECTUS SUPPLEMENT SUMMARY

This summary highlights information contained elsewhere in this prospectus supplement and the accompanying prospectus. This summary may not contain all of the information that may be important to you. You should read the entire prospectus supplement, including Risk Factors, the accompanying prospectus and the documents we incorporate by reference into this prospectus supplement and the accompanying prospectus carefully before making a decision to invest in our common stock We have provided definitions for the oil and gas terms used in this prospectus supplement in the Glossary of Certain Oil and Gas Terms included in this prospectus supplement.

About Our Company

We are an independent oil and gas company engaged in oil and gas acquisition, development, exploitation, production and exploration activities primarily in the Permian Basin, Rocky Mountains, Mid-Continent, Gulf Coast and Michigan regions of the United States. Prior to 2006, we generally emphasized the acquisition of properties that increased our production levels and provided upside potential through further development. Since 2006, we have focused primarily on organic drilling activity and on the development of previously acquired properties, specifically on projects that we believe provide the opportunity for repeatable success and production growth. We believe the combination of acquisitions, subsequent development and organic drilling provides us a broad set of growth alternatives and allows us to direct our capital resources to what we believe to be the most advantageous investments.

As demonstrated by our recent capital expenditure programs, we are increasingly focused on a balance between exploration and development while continuing to selectively pursue acquisitions that complement our existing core properties. Our growth plan is centered on the following activities:

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

We believe that our significant drilling inventory, combined with our operating experience and cost structure, provides us with meaningful organic growth opportunities. Additionally, we expect to continue to build on our successful acquisition track record and selectively pursue property acquisitions that complement our existing core properties. During 2008, we incurred $1,390.5 million in acquisition, development and exploration activities, including $947.0 million for the drilling of 306 gross (125.4 net) wells. Of these new wells, 115.3 (net) resulted in productive completions and 10.2 (net) were unsuccessful, yielding a 92% success rate.

On January 20, 2009, we announced a capital budget of $320.4 million for development and exploration expenditures in 2009 that we expect to fund from internally generated cash flows. We will use this 2009 base capital budget to continue development of our Northern and Central Rockies projects as well as our CO_2 projects. After using the net proceeds from this offering to temporarily reduce amounts outstanding under our credit facility, we expect to use a portion of the proceeds from this offering to increase our 2009 base capital budget by approximately $123.6 million to develop incremental opportunities we have identified in the Northern and Central Rockies. However, we may allocate this portion of the proceeds as well as the balance of the proceeds from this offering to either further develop these incremental projects or to expand the projects in our 2009 base capital budget that indicate the highest return based on drilling results through the time of such allocation. Additional detailed information with respect to our 2009 base capital budget as well as prospects to be drilled with proceeds from this offering is presented below.

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As of December 31, 2008, our estimated proved reserves totaled 239.1 MMBOE, of which 67% were classified as proved developed. These estimated reserves had a pre-tax PV10% value of approximately $1,603.0 million, of which approximately 89% came from properties located in our Permian Basin, Rocky Mountains and Mid-Continent core areas. The following table summarizes our estimated proved reserves as of December 31, 2008 by core area, the corresponding pre-tax PV10% value and our December 2008 average daily production rate:

	Proved Reserves					
Core Area	Oil (MMBbl)(1)	Natural Gas (Bcf)	Total (MMBOE)	% Oil(1)	Pre-Tax PV10% Value(2) (In millions)	December 2008 Average Daily Production (MBOE/d)
Permian Basin	88.1	57.8	97.7	90%	$ 455.2	11.7
Rocky Mountains	49.2	203.9	83.2	59%	548.2	27.7
Mid-Continent	37.2	11.7	39.1	95%	416.2	7.2
Gulf Coast	3.1	41.6	10.1	31%	105.2	5.0
Michigan	2.4	39.7	9.0	27%	78.2	3.5
Total	180.0	354.8	239.1	75%	$ 1,603.0	55.1

(1) Oil includes natural gas liquids.

(2) Pre-tax PV10% may be considered a financial measure that is not calculated in accordance with generally accepted accounting principles in the United States, or GAAP, as defined by the SEC, and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. As of December 31, 2008, our discounted future income taxes were $226.6 million and our standardized measure of discounted future net cash flows was $1,376.4 million. We believe pre-tax PV10% is a useful measure to investors in evaluating the relative monetary significance of our oil and gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV10% and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following is a summary of our changes in quantities of proved oil and gas reserves for the year ended December 31, 2008:

	Oil (MBbl)	Natural Gas (MMcf)

			Total (MBOE)
Balance December 31, 2007	196,318	326,742	250,775(1)
Extensions and discoveries	20,395	57,093	29,910
Sales of minerals in place	(3,919)	(14,277)	(6,298)
Purchases of minerals in place	513	90,329	15,568
Production	(12,448)	(30,419)	(17,517)
Revisions to previous estimates	(20,851)	(74,689)	(33,300)(2)
Balance December 31, 2008	180,008	354,779	239,138

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(1) If the December 31, 2007 total proved reserves had been calculated using prices as of December 31, 2008, the total proved reserves would have been 207.5 MMBOE as compared to December 31, 2008 total proved reserves of 229.9 MMBOE after adjusting 239.1 MMBOE for sales of 6.3 MMBOE and acquisitions of 15.6 MMBOE during 2008. The NYMEX prices per Bbl of oil as of December 31, 2007 and December 31, 2008 were $96.00 and $44.60, respectively. The NYMEX prices per Mcf of natural gas as of December 31, 2007 and December 31, 2008 were $7.10 and $5.63, respectively.

(2) Includes a 39.0 MMBOE reduction in proved reserves due to decreases in prices of oil and natural gas from December 31, 2007 to December 31, 2008.

Business Strategy

Our goal is to generate meaningful growth in both production and free cash flow by investing in oil and gas projects with attractive rates of return on capital employed. To date, we have achieved this goal through both the acquisition of reserves and continued field development in our core areas. Because of the extensive property base we have built, we are pursuing several economically attractive oil and gas opportunities to exploit and develop properties as well as explore our acreage positions for additional production growth and proved reserves. Specifically, we have focused, and plan to continue to focus, on the following:

Pursuing High-Return Organic Reserve Additions. The development of large resource plays such as our Williston Basin and Piceance Basin projects has become one of our central objectives. We have assembled 125,557 gross (83,606 net) acres on the eastern side of the Williston Basin in North Dakota in an active oil development play at our Sanish field area, where the Middle Bakken reservoir is oil productive. We have drilled and completed 49 successful Bakken wells (27 operated) in our Sanish field acreage that had a combined production rate of 7,445 BOE/d during December 2008. With the acquisition of Equity Oil Company in 2004, we acquired mineral interests and federal oil and gas leases in the Piceance Basin of Colorado, where we have found the Mesaverde formation to be gas productive at our Boies Ranch and Jimmy Gulch prospect areas. Our initial drilling results in both projects have been positive. In the Piceance acreage, we have drilled and completed 23 successful wells that had a combined net production rate of 9,473 Mcf/d of natural gas during December 2008. In addition to development of our core areas, we have identified incremental opportunities in the Sanish field, Parshall field and Lewis & Clark prospect in the Williston Basin, the Sulphur Creek field Jimmy Gulch and Wasatch prospects in the Piceance Basin and the Hatfield prospect in the Green River Basin.

Developing and Exploiting Existing Properties. Our existing property base and our acquisitions over the past five years have provided us with numerous low-risk opportunities for exploitation and development drilling. As of December 31, 2008, we have identified a drilling inventory of over 1,400 gross wells that we believe will add substantial production over the next five years. Our drilling inventory consists largely of the development of our non-proved reserves on which we have spent significant time evaluating the costs and expected results. Additionally, we have several opportunities to apply and expand enhanced recovery techniques that we expect will increase proved reserves and extend the productive lives of our mature fields. In 2005, we acquired two large oil fields, the Postle field, located in the Oklahoma Panhandle, and the North Ward Estes field, located in the Permian Basin of West Texas. We have experienced and anticipate further significant production increases in these fields over the next seven years through the use of secondary and tertiary recovery techniques. In these fields, we are actively injecting water and CO_2 and executing extensive re-development, drilling and completion operations, as well as enhanced gas handling and treating capability.

Growing Through Accretive Acquisitions. From 2004 to 2008, we completed 13 separate acquisitions of producing properties for estimated proved reserves of 226.9 MMBOE, as of the effective dates of the acquisitions. Our experienced team of management, engineering and geoscience professionals has developed and refined an acquisition program designed to increase reserves and complement our existing properties, including identifying and evaluating acquisition opportunities, negotiating and closing purchases and managing acquired properties. We intend to selectively acquire properties complementary to our core operating areas.

Disciplined Financial Approach. Our goal is to remain financially strong, yet flexible, through the prudent management of our balance sheet and active management of commodity price volatility. We have historically funded our acquisitions and growth activity through a combination of equity and debt issuances, bank borrowings and internally generated cash flow, as appropriate, to maintain our strong financial position. From time to time, we monetize non-core properties and use the net proceeds from these asset sales to repay debt under our credit agreement. For example, we established the Whiting USA Trust I, an oil and gas net profits interest trust, by offering trust units, which are traded on the New York Stock Exchange under the symbol WHX , to the public in April 2008, which resulted in $193.7 million in net proceeds to us that we used to repay debt. To support cash flow generation on our existing properties and help ensure expected cash flows from acquired properties, we periodically enter into derivative contracts. Typically, we use costless collars to provide an attractive base commodity price level, while maintaining the ability to benefit from improvements in commodity prices.

Competitive Strengths

We believe that our key competitive strengths lie in our balanced asset portfolio, our experienced management and technical team and our commitment to effective application of new technologies.

Balanced, Long-Lived Asset Base. As of December 31, 2008, we had interests in 8,464 gross (3,558 net) productive wells across 992,392 gross (514,881 net) developed acres in our five core geographical areas. We believe this geographic mix of properties and organic drilling opportunities, combined with our continuing business strategy of acquiring and exploiting properties in these areas, presents us with multiple opportunities in executing our strategy because we are not dependent on any particular producing regions or geological formations. Our proved reserve life is approximately 13.6 years based on year-end 2008 proved reserves and 2008 production.

Experienced Management Team. Our management team averages 25 years of experience in the oil and gas industry. Our personnel have extensive experience in each of our core geographical areas and in all of our operational disciplines. In addition, each of our acquisition professionals has at least 28 years of experience in the evaluation, acquisition and operational assimilation of oil and gas properties.

Commitment to Technology. In each of our core operating areas, we have accumulated detailed geologic and geophysical knowledge and have developed significant technical and operational expertise. In recent years, we have developed considerable expertise in conventional and 3-D seismic imaging and interpretation. Our technical team has access to approximately 5,934 square miles of 3-D seismic data, digital well logs and other subsurface information. This data is analyzed with advanced geophysical and geological computer resources dedicated to the accurate and efficient characterization of the subsurface oil and gas reservoirs that comprise our asset base. In addition, our information systems enable us to update our production databases through daily uploads from hand held computers in the field. With the acquisition of the Postle and North Ward Estes properties, we have assembled a team of 14 professionals averaging over 20 years of expertise in managing CO_2 floods. This provides us with the ability to pursue other CO_2 flood targets and employ this technology to add reserves to our portfolio. This commitment to technology has increased the productivity and efficiency of our field operations and development activities.

Recent Developments

2008 Production Results, 2008 Estimated Reserves and Current Liquidity Position

On January 20, 2009, we announced our fourth quarter and full-year 2008 preliminary production results, estimated proved reserves as of December 31, 2008 and liquidity position as of December 31, 2008. Preliminary production for the three months ended December 31, 2008 was 5.11 MMBOE, which is an increase of 10% over third quarter 2008 production of 4.64 MMBOE. This equates to an average daily rate in the fourth quarter of 55,540 BOE/d. Preliminary production for the year ended December 31, 2008 increased

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19% to 17.52 MMBOE compared to 14.71 MMBOE for the year ended December 31, 2007. Our average sales prices per Bbl of oil and per Mcf of natural gas during the fourth quarter of 2008 declined to $47.37 and $4.38, respectively, compared to $108.04 and $8.65, respectively, during the third quarter of 2008. Our December 2008 average daily production was 55.14 MBOE/d.

As of December 31, 2008, our estimated proved reserves totaled 239.1 MMBOE. Our estimated proved reserves by core area are set forth in the table under About Our Company above.

As of December 31, 2008, we had cash of $9.6 million, $620.0 million in borrowings and $2.8 million in letters of credit outstanding under Whiting Oil and Gas Corporation s credit agreement and $620.0 million of senior subordinated notes outstanding. The borrowing base under Whiting Oil and Gas Corporation s credit agreement is $900.0 million resulting in $277.2 million of available borrowing capacity at December 31, 2008.

2009 Capital Budget

On January 20, 2009, we announced our capital budget for development and exploration expenditures in 2009 to be approximately $320.4 million. More detail relating to specific items included in our 2009 budget is provided under 2009 Capital Budget and Major Development Areas below.

Hedging Program

On December 23, 2008, we announced that we had completed our current hedging program. In connection with our conveyance of a term net profits interest to Whiting USA Trust I, we conveyed to Whiting USA Trust I the rights to future hedge payments we make or receive on certain of our derivative contracts from 2008 through 2012. Due to the terms of the net profits interest and our ownership of trust units, we retain 24.2% of the future economic results of such hedges. While we continue to review economically attractive opportunities with respect to hedges, the following tables summarize our current oil and natural gas hedges.

The following table summarizes our crude oil collars, including our 24.2% interest in Whiting USA Trust I:

Collar Period	**Contracted Volume (Bbls per Month)**	**Weighted Average NYMEX Price Collar Range (per Bbl)**			**As a Percentage of December 2008 Oil Production**
Year Ending December 31, 2009	520,656	$	57.57	$73.95	42.5%
Year Ending December 31, 2010	420,524	$	62.34	$83.00	34.3%
Year Ending December 31, 2011	369,587	$	61.68	$86.26	30.2%
Year Ending December 31, 2012	338,758	$	61.70	$87.63	27.7%
Eleven Months Ending November 30, 2013	280,909	$	60.33	$81.46	22.9%

We currently do not have any natural gas collars other than those relating to Whiting USA Trust I. The following table summarizes our 24.2% share of the Whiting USA Trust I natural gas hedges:

	Contracted	**As a Percentage**

Collar Period	Volumes (MMBtu per Month)	Weighted Average NYMEX Price Collar Range (per MMBtu)			of December 2008 Natural Gas Production
Year Ending December 31, 2009	48,152	$	6.50	$17.11	1.7%
Year Ending December 31, 2010	41,283	$	6.50	$15.06	1.4%
Year Ending December 31, 2011	36,376	$	6.50	$14.62	1.3%
Year Ending December 31, 2012	32,000	$	6.50	$14.27	1.1%

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We also have the following fixed-price natural gas contracts in place:

Fixed Price Contracts		Natural Gas Volumes in MMBtu per Month	2009 Contract Price(1) per MMBtu	As a Percentage of December 2008 Natural Gas Production
January 2009	May 2011	67,000	$ 5.14	2.3%
January 2009	September 2012	23,000	$ 4.56	0.8%

(1) Annual 4% price escalation on fixed-price contracts.

2009 Capital Budget and Major Development Areas

Our previously announced capital budget of $320.4 million for development and exploration expenditures in 2009 is allocated among our major development areas as indicated in the chart below. Of our existing potential projects, we believe these present the opportunity for the highest return and most efficient use of our capital expenditures. We expect to fund these capital expenditures with net cash provided by our operating activities assuming current oil and natural gas prices. To the extent net cash provided by operating activities is higher or lower than currently anticipated, we would adjust our capital budget accordingly. The chart below does not include the development we expect to pursue with the proceeds of this offering, which is discussed under Prospects to be Drilled in 2009 with Offering Proceeds below.

Development Area	Average Working Interest (%)	Average Net Revenue Interest (%)	2009 Planned Capital Expenditures (In millions)
Northern Rockies			
Sanish Field	74%	59%	$ 150.6
Parshall Field	16%	12%	12.1
Area Sub Total			$ 162.7
CO_2 Projects			
North Ward Estes Field(1)	100%	82%	$ 97.8
Postle Field(1)	97%	85%	31.5
Area Sub Total			$ 129.3
Central Rockies			

Flat Rock Field	100%	79%	$	19.1
Sulphur Creek Field	75%	69%		4.4
Hatch Point Prospect	53%	44%		3.5
Rangely Weber Sand Unit	5%	4%		1.4
Area Sub Total			$	28.4
Total			$	320.4

(1) 2009 planned capital expenditures at our CO_2 projects include \$36.9 million at North Ward Estes and \$15.3 million at Postle for purchased CO_2.

The following are descriptions of each of these major development areas:

Northern Rockies Sanish and Parshall Fields

Sanish Field. Our Sanish area in Mountrail County, North Dakota encompasses 125,557 gross acres (83,606 net acres). December 2008 net production in the Sanish field averaged 7.5 MBOE/d, an 832%

increase from 0.8 MBOE/d in December 2007. As of January 12, 2009, we have participated in 65 wells (27 operated) that target the Bakken formation, of which 49 are producing, seven are in the process of completion and nine are being drilled. Of these operated wells, 23 were completed in 2008. We have completed and placed on production our first Bakken infill well in the Sanish field, the McNamara 42-26H. This well was drilled between two horizontal Bakken producers, the Locken 11-22H and the Liffrig 11-27H. The initial production rate at the McNamara well was 2,170 BOE/d (measured December 8, 2008), which falls between the initial production rates of the two offset wells. There was no indication of communication or interference with either of the offset wells. Based on these results, we expect to develop our leases with two 10,000-foot horizontal wells in each 1,280-acre spacing unit. We have also completed our first Three Forks horizontal well in the Sanish field, the Braaflat 21-11TFH. The initial production rate at the Braaflat well was 1,005 BOE/d (measured January 1, 2009). Production and pressure data from this well will be analyzed over several months to determine the viability of developing the Three Forks.

We intend to drill an additional 28 operated Bakken wells in the Sanish field during 2009, with an average working interest of 74%, five of which were being drilled at January 12, 2009. We expect an average of six drilling rigs to be working in the Sanish field during 2009. We expect our net capital expenditures in the Sanish field during 2009 to be approximately $150.6 million.

Parshall Field. Immediately east of the Sanish field is the Parshall field, where we own interests in 73,760 gross acres (18,315 net acres). Our net production from the Parshall field averaged 6.7 MBOE/d in December 2008, a 341% increase from 1.5 MBOE/d in December 2007. As of January 12, 2009, we have participated in 95 Bakken wells, the majority of which are operated by EOG Resources, Inc., of which 85 are producing, four are in the process of completion and six are drilling. Of these wells, 64 were completed in 2008. We intend to participate in the drilling of an additional nine wells in the Parshall field during 2009, with an average working interest of approximately 16%. We expect our net capital expenditures in the Parshall field during 2009 to be approximately $12.1 million.

CO_2 Projects North Ward Estes and Postle

We continue to have significant development and related infrastructure activity on the Postle and North Ward Estes fields acquired in 2005, which has resulted in reserve and production increases.

North Ward Estes Field. The North Ward Estes field includes six base leases with 100% working interest in approximately 58,000 gross and net acres in Ward and Winkler Counties, Texas. The North Ward Estes field is responding positively to our CO_2 flood, which we initiated in May 2007. As of December 31, 2008, we were injecting 123 MMcf/d of CO_2 in this field. Production from the field has increased 29% from a net 5.1 MBOE/d in December 2007 to a net 6.6 MBOE/d in December 2008. In this field, we are developing new and reactivated wells for water and CO_2 injection and production purposes. Additionally, we plan to install oil, gas and water processing facilities in five phases through 2015, and we estimate that the first three phases will be substantially complete by December 2009. We expect our net capital expenditures in the North Ward Estes field during 2009 to be approximately $97.8 million, of which $36.9 million is for CO_2.

Postle Field. The Postle field, located in Texas County, Oklahoma, includes five producing units and one producing lease covering a total of approximately 25,600 gross (24,225 net) acres with working interests of 94% to 100%. Four of the units are currently active CO_2 enhanced recovery projects. Our expansion of the CO_2 flood at the Postle field continues to generate positive results. As of December 31, 2008, we were injecting 142 MMcf/d of CO_2 in this field. Production from the field has increased 22% from a net 5.8 MBOE/d in December 2007 to a net 7.1 MBOE/d in December 2008. Operations are under way to expand CO_2 injection into the northern part of the fourth unit, HMU, and to optimize flood patterns in the existing CO_2 floods, with one drilling rig and four workover rigs in the field as of the end of 2008. These expansion projects include the restoration of shut-in wells and the drilling of new producing and injection wells. We expect our net capital expenditures in the Postle field during 2009 to be approximately

$31.5 million, of which $15.3 million is for CO_2.

Central Rockies

In the Flat Rock field area in Uintah County, Utah, we have an acreage position consisting of 22,029 gross (11,533 net) acres. In this area, initial production rates of ten wells drilled in the Entrada formation by other operators have ranged from 0.7 MMcf/d to 6.1 MMcf/d. We recently completed two wells in the Entrada formation that had initial gross production rates of 4.1 MMcf/d and 9.3 MMcf/d, respectively. We are also the operator of six Entrada wells drilled by a prior operator on our acreage that had initial production rates ranging from 1.9 MMcf/d to 6.5 MMcf/d. We currently have four additional Entrada wells planned for this field for 2009 at an estimated net cost of approximately $19.1 million.

In the Sulphur Creek field in Rio Blanco County, Colorado in the Piceance Basin, we executed an acreage trade effective December 1, 2008 with a third party that consolidated our acreage position. As a result of such trade, we now own 8,424 gross (4,338 net) acres in the Sulphur Creek field area. We expect our net capital expenditures in our Sulphur Creek field during 2009 to be approximately $4.4 million.

At our Hatch Point prospect in San Juan County, Utah in the Paradox Basin, we have an exploratory horizontal well planned for 2009 in the Cane Creek zone at an estimated cost of approximately $6.5 million ($3.5 million net to us).

At the Rangely Weber Sand Unit in Rio Blanco County, Colorado, we own a 4.6% working interest and intend to continue participating in the development of this large field operated by Chevron that produced over 13,600 gross BOE/d during December 2008. We expect our net 2009 capital expenditures in the Rangely field to be approximately $1.4 million.

Prospects to be Drilled in 2009 with Offering Proceeds

After using the net proceeds from this offering to temporarily reduce amounts outstanding under our credit facility, we expect to use a portion of the proceeds from this offering to increase our 2009 base capital budget by approximately $123.6 million to develop incremental opportunities we have identified in the Northern and Central Rockies as a result of our drilling results during the fourth quarter of 2008 in these prospect areas. However, we may allocate this portion of the proceeds as well as the balance of the proceeds from this offering to either further develop these incremental projects or to expand the projects in our 2009 base capital budget that indicate the highest return based on drilling results through the time of such allocation. We believe that the initial wells we have drilled in these areas indicate results as attractive as the projects in our 2009 base capital budget at current oil and natural gas prices. These planned expenditures are described in more detail below:

Areas	Completion Interval	Wells	Estimated per Well Capital Expenditures (In millions)	Average Working Interest (%)	Average Net Revenue Interest (%)	2009 Planned Capital Expenditures (In millions)
Northern Rockies						
Sanish Field	Middle Bakken	12	$ 7.0	64.6%	52.5%	$ 54.3
Lewis & Clark Prospect	Three Forks	6	$ 4.0	64.0%	52.9%	$ 15.4
Parshall Field	Middle Bakken	9	$ 6.0	18.4%	14.7%	$ 9.9
Central Rockies						

Sulphur Creek Field									
Jimmy Gulch									
Mesaverde	Mesaverde	9	$	3.5	90.0%	76.5%	$	28.4
Hatfield Prospect	Niobrara	6	$	1.5	100.0%	80.0%	$	9.0
Sulphur Creek Field								
Wasatch	Wasatch	6	$	1.5	73.4%	67.9%	$	6.6
Total		48					$	123.6

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The following are descriptions of these prospect areas that we plan to drill with proceeds from this offering.

Northern Rockies

Sanish Field. We have identified an incremental twelve wells to drill in the Sanish field in 2009 at a total estimated net capital cost of $54.3 million in addition to the wells to be drilled with the $150.6 million of capital expenditures described under 2009 Capital Budget and Major Development Areas above. These additional wells would accelerate the development of this field where, as of January 12, 2009, we have participated in 65 wells (27 operated), of which 49 wells are producing from the Middle Bakken formation, seven wells are in the process of completion and nine wells are being drilled. The productive wells in the Sanish Field completed during 2008 have averaged 954 BOE/d during their first 30 days of production and 836 BOE/d during their first 60 days of production.

Lewis & Clark Prospect. We have assembled 181,749 gross (111,501 net) acres in our Lewis & Clark prospect along the Bakken Shale pinch-out in the southern Williston Basin. In this area, the Upper Bakken shale is thermally mature, moderately over pressured, and has charged reservoir zones within the immediately underlying Three Forks formation. On December 13, 2008 we completed our first horizontal test well in this area, which had an initial production rate of over 1,000 BOE/d. We are currently drilling a second well and plan to drill six additional locations in 2009 based on the results of the first two wells. In this area, we can horizontally drill many of our Three Forks zone wells from existing well bores that were initially drilled for deeper objectives, which we believe reduces the cost of a new well from an estimated $7 million to an estimated $4 million per new well and a total estimated net capital cost of approximately $15.4 million.

Parshall Field. We have identified an incremental nine non-operated wells to drill in the Parshall field in 2009 at a total estimated net capital cost of $9.9 million in addition to the nine non-operated wells to be drilled with the $12.1 million of capital expenditures described under 2009 Capital Budget and Major Development Areas above.

Central Rockies

Sulphur Creek Field Jimmy Gulch Mesaverde. The Jimmy Gulch prospect in the Sulphur Creek field area in the Piceance Basin is one square mile in area and is an eastern extension of the Boies Ranch prospect where we have drilled 34 productive wells in the Mesaverde formation as of December 31, 2008. Jimmy Gulch was tested with three wells that were producing at a combined gross rate of 7.4 MMcf/d (5.7 MMcf/d net) on January 8, 2009. We have identified another nine locations to drill in 2009 at a total estimated net capital cost of $28.4 million.

Hatfield Prospect. In southern Wyoming in the Hatfield prospect area, we have a large acreage position covering over 80 square miles and encompassing 53,164 gross (31,907 net) acres. In this area, cumulative production from four vertical Niobrara wells drilled by other operators has ranged from approximately 22,000 to 124,000 barrels of oil per well. In September 2008, we drilled the Beckman Canyon 21-24D, a vertical well to test the Niobrara formation as well as a deeper zone. During drilling operations in the Niobrara at a depth of approximately 3,500 feet, oil flowed to the surface and oil shows were seen in the drill cuttings. We will conduct completion operations on this well in February 2009. In December 2008, we drilled the Artus 19-33, a horizontal Niobrara well. As of January 12, 2009, we have commenced completion operations on this well. We believe that current horizontal drilling techniques will improve recovery compared to vertical drilling used at historic wells in this area. We have identified six additional drilling locations for 2009 at a total estimated net capital cost of $9.0 million to further define and begin development of this discovery.

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Sulphur Creek Field Wasatch. We drilled our first Wasatch zone well in the Sulphur Creek field in the Piceance Basin in late 2008 and early 2009. We targeted the Wasatch based on our observation of gas shows seen while drilling through the Wasatch zone at depths of approximately 5,000 feet while drilling to the deeper Mesaverde target at a depth of approximately 10,000 feet. These results along with a study of the production data from Wasatch wells drilled in the 1970 s and 1980 s in the area of our Boies Ranch prospect provided the basis for drilling this well. Gas shows were seen while drilling, gas was indicated on well logs, and the first well penetrated approximately 50 feet of net Wasatch zone that we believe to be gas productive. Due to such results, we have identified an incremental six wells to drill in 2009 at a total estimated net capital cost of $6.6 million in addition to the wells to be drilled with the $4.4 million of capital expenditures described under 2009 Capital Budget and Major Development Areas above.

Corporate Information

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

The Offering

The following is a brief summary of some of the terms of this offering. For a more complete description of our common stock, see Description of Capital Stock in the accompanying prospectus.

Common stock offered	8,000,000 shares
Shares outstanding after the offering	50,583,218 shares
Use of proceeds	After using the net proceeds from this offering to temporarily reduce amounts outstanding under our credit facility, we expect to use a portion of the proceeds from this offering to increase our 2009 base capital budget by approximately $123.6 million to develop incremental opportunities we have identified in the Northern and Central Rockies. However, we may allocate this portion of the proceeds as well as the balance of the proceeds from this offering to either further develop these incremental projects or to expand the projects in our 2009 base capital budget that indicate the highest return based on drilling results through the time of such allocation. See Prospects to be Drilled in 2009 with Offering Proceeds , 2009 Capital Budget and Major Development Areas and Use of Proceeds.
Risk factors	Please read Risk Factors and the other information in this prospectus supplement and the accompanying prospectus for a discussion of factors you should carefully consider 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 42,583,218 shares outstanding as of December 31, 2008. If the over-allotment option is exercised in full, we will issue and sell an additional 1,200,000 shares of our common stock.

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Summary Historical Financial Information

The following summary historical financial information as for the years ended December 31, 2005, 2006 and 2007 and as of December 31, 2005, 2006 and 2007 has been derived from, and is qualified by reference to, our audited consolidated financial statements and related notes. The following summary historical financial information for the nine months ended September 30, 2007 and 2008 and as of September 30, 2007 and 2008 has been derived from, and is qualified by reference to, our unaudited consolidated financial statements and related notes. This information is only a summary and you should read it in conjunction with our financial statements and related notes incorporated by reference in this prospectus supplement and the accompanying 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, 2008 are not necessarily indicative of the results to be expected for the full fiscal year.

	Year Ended December 31,			Nine Months Ended September 30,	
	2005	2006	2007	2007	2008
	(In millions, except per share data)				
				(Unaudited)	
Consolidated Income Statement Information:					
Revenues and other income:					
Oil and natural gas sales	$ 573.2	$ 773.1	$ 809.0	$ 558.0	$ 1,102.7
Loss on oil and natural gas hedging activities	(33.4)	(7.5)	(21.2)	(2.1)	(112.9)
Gain on sale of oil and gas properties		12.1	29.7	29.7	
Amortization of deferred gain on sale					7.7
Interest income and other	0.6	1.1	1.2	0.8	0.8
Total revenues and other income	$ 540.4	$ 778.8	$ 818.7	$ 586.4	$ 998.3
Costs and expenses:					
Lease operating	$ 111.6	$ 183.6	$ 208.9	$ 154.5	$ 177.9
Production taxes	36.1	47.1	52.4	34.9	72.0
Depreciation, depletion and amortization	97.6	162.8	192.8	143.2	179.6
Exploration and impairment	16.7	34.5	37.3	26.3	30.5
General and administrative	30.6	37.8	39.0	27.9	51.9
Change in Production Participation Plan liability	9.7	6.2	8.6	6.4	27.0
Interest expense	42.0	73.5	72.5	56.5	48.8
Loss on mark-to-market derivatives				1.2	7.0
Total costs and expenses	$ 344.3	$ 545.5	$ 611.5	$ 450.9	$ 594.7
Income before income taxes	$ 196.1	$ 233.3	$ 207.2	$ 135.5	$ 403.6
Income tax expense	74.2	76.9	76.6	50.6	148.4
Net income	$ 121.9	$ 156.4	$ 130.6	$ 84.9	$ 255.2
Net income per common share, basic	$ 3.89	$ 4.26	$ 3.31	$ 2.20	$ 6.03

Net income per common share, diluted	$ 3.88	$ 4.25	$ 3.29	$ 2.19	$ 6.01
Other Financial Information:					
Net cash provided by operating activities	$ 330.2	$ 411.2	$ 394.0	$ 272.6	$ 611.5
Capital expenditures	$ 1,126.9	$ 552.0	$ 519.6	$ 370.5	$ 1,051.6
EBITDA(1)	$ 335.7	$ 469.6	$ 472.5	$ 335.2	$ 632.0

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	As of December 31,			As of September 30,	
	2005	2006	2007	2007	2008
			(In millions)	(Unaudited)	
Consolidated Balance Sheet Information:					
Total assets	$ 2,235.2	$ 2,585.4	$ 2,952.0	$ 2,811.0	$ 3,835.1
Total debt	$ 875.1	$ 995.4	$ 868.2	$ 836.7	$ 1,118.6
Stockholders equity	$ 997.9	$ 1,186.7	$ 1,490.8	$ 1,472.9	$ 1,779.4

(1) 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 for the periods presented:

	Year Ended December 31,			Nine Months Ended September 30,	
	2005	2006	2007	2007	2008
			(In millions)		
Net income	$ 121.9	$ 156.4	$ 130.6	$ 84.9	$ 255.2
Income tax expense	74.2	76.9	76.6	50.6	148.4
Interest expense	42.0	73.5	72.5	56.5	48.8
Depreciation, depletion and amortization	97.6	162.8	192.8	143.2	179.6
EBITDA	$ 335.7	$ 469.6	$ 472.5	$ 335.2	$ 632.0

Summary Historical Reserve and Operating Data

The following tables present summary information regarding our estimated net proved oil and natural gas reserves as of December 31, 2006, 2007 and 2008 and our historical operating data for the years ended December 31, 2005, 2006 and 2007. All calculations of estimated net proved reserves have been made in accordance with the rules and regulations of the SEC and, except as otherwise indicated, give no effect to federal or state income taxes.

	As of December 31,		
	2006	2007	2008
Reserve Data:			
Total estimated proved developed reserves:			
Oil (MMBbls)	122.5	127.3	121.0
Natural gas (Bcf)	226.5	237.0	229.2
Total (MMBOE)	160.2	166.8	159.2
Total estimated proved reserves:			
Oil (MMBbls)	195.0	196.3	180.0
Natural gas (Bcf)	318.9	326.7	354.8
Total (MMBOE)	248.1	250.8	239.1
Pre-tax PV10% value (in millions)(1)(2)	$ 3,352.2	$ 5,858.3	$ 1,603.0
Standardized measure of discounted future net cash flows (in millions)(1)(3)	$ 2,392.2	$ 4,011.7	$ 1,376.4

(1) The December 31, 2006 amount was calculated using a period end average realized oil price of $54.81 per Bbl and a period end average realized natural gas price of $5.41 per Mcf, the December 31, 2007 amount was calculated using a period end average realized oil price of $88.62 per Bbl and a period end average realized natural gas price of $6.31 per Mcf and the December 31, 2008 amount was calculated using a period end average realized oil price of $44.60 per Bbl and a period end average realized natural gas price of $5.63 per Mcf.

(2) Pre-tax PV10% may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV10% is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. Our discounted future income taxes were $960.0 million as of December 31, 2006, $1,846.6 million as of December 31, 2007 and $226.6 million as of December 31, 2008. We believe pre-tax PV10% is a useful measure to investors in evaluating the relative monetary significance of our oil and gas properties. We further believe investors may utilize our pre-tax PV10% as a basis for comparison of the relative size and value of our reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and gas properties and acquisitions. However, pre-tax PV10% is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV10% and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

(3) The standardized measure of discounted future net cash flows, which reflects the after-tax present value of discounted future net cash flows, relating to proved oil and natural gas reserves were prepared in accordance with the provisions of Statement of Financial Accounting Standards No. 69. Future cash inflows were computed by applying prices at year end to estimated future production. Future production and development costs are

computed by estimating the expenditures to be incurred in developing and producing the proved oil and natural gas reserves at year end, based on year-end costs and assuming continuation of existing economic conditions. Future net cash flows are discounted at a rate of 10% annually to derive the standardized measure of discounted future net cash flows. This calculation procedure does not necessarily result in an estimate of the fair market value or the present value of our oil and gas properties.

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	Year Ended December 31,			Nine Months Ended September 30,	
	2005	2006	2007	2007	2008
Operating Data:					
Net Production:					
Oil (MMBbls)	7.0	9.8	9.6	7.1	8.7
Natural gas (Bcf)	30.3	32.1	30.8	23.3	22.4
Total production (MMBOE)	12.1	15.2	14.7	11.0	12.4
Net Sales (in millions)(1):					
Oil	$ 360.4	$ 561.2	$ 618.5	$ 414.8	$ 904.1
Natural gas	$ 212.8	$ 211.9	$ 190.5	$ 143.2	$ 198.6
Total oil and natural gas	$ 573.2	$ 773.1	$ 809.0	$ 558.0	$ 1,102.7
Average sales prices:					
Oil (per Bbl)	$ 51.26	$ 57.27	$ 64.57	$ 58.37	$ 104.21
Effect of oil hedges on average price (per Bbl)	$ (2.72)	$ (0.95)	$ (2.21)	$ (0.29)	$ (13.01)
Oil net of hedging (per Bbl)	$ 48.54	$ 56.32	$ 62.36	$ 58.08	$ 91.20
Average NYMEX price	$ 56.61	$ 66.25	$ 72.30	$ 66.12	$ 113.38
Natural gas (per Mcf)	$ 7.03	$ 6.59	$ 6.19	$ 6.14	$ 8.87
Effect of natural gas hedges on average price (per Mcf)	$ (0.47)	$ 0.06	$	$	$
Natural gas net of hedging (per Mcf)	$ 6.56	$ 6.65	$ 6.19	$ 6.14	$ 8.87
Average NYMEX price	$ 8.64	$ 7.23	$ 6.86	$ 6.83	$ 9.75
Cost and expenses (per BOE):					
Lease operating expenses	$ 9.24	$ 12.12	$ 14.20	$ 14.05	$ 14.33
Production taxes	$ 2.99	$ 3.11	$ 3.56	$ 3.17	$ 5.80
Depreciation, depletion and amortization expenses	$ 8.08	$ 10.74	$ 13.11	$ 13.02	$ 14.47
General and administrative expenses	$ 2.53	$ 2.49	$ 2.66	$ 2.54	$ 4.18

(1) Before consideration of hedging transactions

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RISK FACTORS

You should carefully consider each of the risks described below, together with all of the other information contained or incorporated by reference in this prospectus supplement and the accompanying 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 Gas Industry and Our Business

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

The oil and gas markets are very volatile, and we cannot predict future oil and natural gas prices. The price we receive for our oil and natural gas production heavily influences our revenue, profitability, access to capital and future rate of growth. The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include, but are not limited to, the following:

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

Furthermore, the recent worldwide financial and credit crisis has reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide. The shortage of liquidity and credit combined with recent substantial losses in worldwide equity markets has lead to a worldwide economic recession. The slowdown in economic activity caused by such recession has reduced worldwide demand for energy and resulted in lower oil and natural gas prices. Oil prices declined from record levels in early July 2008 of over $140 per Bbl to below $40 per Bbl in December 2008, while natural gas prices have declined from over $13 per Mcf to below $6 per Mcf over the same period. In addition, the forecasted prices for 2009 have also declined.

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 and therefore potentially lower our reserve bookings. 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. For example, we expect to fund our 2009 base capital budget of $320.4 million through net cash provided by our operating activities. To the extent commodity prices received from production are insufficient to fund this budget, we will be required to reduce capital spending or borrow any such shortfall. Lower oil and natural gas prices may also reduce the amount of our borrowing base under our credit agreement, which is determined at the discretion of the lenders based on the collateral value of our proved reserves that have been mortgaged to the lenders, and is subject to regular redeterminations on May 1 and November 1 of each year, as well as special redeterminations described in the credit agreement.

The global financial crisis may have impacts on our business and financial condition that we currently cannot predict.

The continued credit crisis and related turmoil in the global financial system may have an impact on our business and our financial condition, and we may face challenges if conditions in the financial markets do not improve. Our ability to access the capital markets may be restricted at a time when we would like, or need, to raise financing, which could have an impact on our flexibility to react to changing economic and business conditions. The economic situation could have an impact on our lenders or customers, causing them to fail to meet their obligations to us. Additionally, market conditions could have an impact on our commodity hedging arrangements if our counterparties are unable to perform their obligations or seek bankruptcy protection.

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 development, exploitation, production and exploration 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 . . . later in this prospectus supplement for a discussion of the uncertainty involved in these processes. Our cost of drilling, completing and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel drilling, including the following:

- delays imposed by or resulting from compliance with regulatory requirements;
- pressure or irregularities in geological formations;
- shortages of or delays in obtaining equipment, including drilling rigs, CO_2 and qualified personnel;
- equipment failures or accidents;
- adverse weather conditions, such as hurricanes and storms;
- reductions in oil and natural gas prices; and
- title problems.

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

We describe some of our current prospects and our plans to explore those prospects in this prospectus supplement. A prospect is a property on which we have identified what our geoscientists believe, based on available seismic and geological information, to be indications of oil or gas. Our prospects are in various stages of evaluation, ranging from a prospect which is ready to drill to a prospect that will require substantial additional seismic data processing and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or gas will be present or, if present, whether oil or gas will be present in commercial quantities. In addition, because of the wide variance that results from different equipment used to test the wells, initial flowrates may not be indicative of sufficient oil or gas quantities in a particular field. The analogies we draw from available data from other wells, more fully explored prospects or producing fields may not be applicable to our drilling prospects. We may terminate our drilling program for a prospect if results do not merit further investment.

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

We have specifically identified and scheduled drilling locations as an estimation of our future multi-year drilling activities on our existing acreage including the locations included in our budget for 2009. As of December 31, 2008, we had identified a drilling inventory of over 1,400 gross drilling locations. These scheduled drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including oil and natural gas prices, the availability of capital, including our ability to fund our 2009 base capital budget of $320.4 million through net cash provided by our operating activities, costs of oil field goods and services, drilling results, regulatory approvals and other factors. Because of these uncertainties, we do not know if the numerous potential drilling locations we have identified will ever be drilled or if we will be able to produce oil or gas from these or any other potential drilling locations. As such, our actual drilling activities may materially differ from those presently identified, which could adversely affect our business.

We have been an early entrant into new or emerging plays; as a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline and we may incur impairment charges if drilling results are unsuccessful.

While our costs to acquire undeveloped acreage in new or emerging plays have generally been less than those of later entrants into a developing play, our drilling results in these areas are more uncertain than drilling results in areas that are developed and producing. Since new or emerging plays have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. Therefore, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful. Furthermore, if drilling results are unsuccessful, we may be required to write down the carrying value of our undeveloped acreage in new or emerging plays. For the fourth quarter of 2008, we expect to record a $10.9 million non-cash impairment charge to income to write down a portion of our $18.4 million cost basis in unproved properties in the central Utah Hingeline play. We may also incur such impairment charges in the future, which could have a material adverse effect on our results of operations in the period taken.

Our use of enhanced recovery methods creates uncertainties that could adversely affect our results of operations and financial condition.

One of our business strategies is to commercially develop oil reservoirs using enhanced recovery technologies. For example, we inject water and CO_2 into formations on some of our properties to increase the production of oil and natural gas. The additional production and reserves attributable to the use of these enhanced recovery methods are inherently difficult to predict. If our enhanced recovery programs do not allow for the extraction of oil and gas in the manner or to the extent that we anticipate, our future results of operations and financial condition could be materially adversely affected. Additionally, our ability to utilize CO_2 as an enhanced recovery technique is subject to our ability to obtain sufficient quantities of CO_2. Our CO_2 contracts permit the suppliers to reduce the amount of CO_2 they provide to us in certain circumstances. If this occurs, we may not have sufficient CO_2 to produce oil and natural gas in the manner or to the extent that we anticipate. These contracts are also structured as take-or-pay arrangements, which require us to continue to make payments even if we decide to terminate or reduce our use of CO_2 as part of our enhanced recovery techniques.

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

As of December 31, 2008, undeveloped reserves comprised 46.5% of the North Ward Estes field s total estimated proved reserves and 16.8% of Postle field s estimated total proved reserves. To fully develop these reserves, we expect to incur total future development costs of $410.1 million at the North Ward Estes field and $84.5 million at the Postle field. During 2007 and 2006, the estimated future capital expenditures necessary to develop the proved reserves at the North Ward Estes field and Postle field increased substantially. The increases were due to several factors, including equipment and service cost inflation, higher CO_2 unit costs and volumes, higher costs associated with the expanded scope of previously identified projects, as well as new projects identified during 2006. Together, these fields encompass 59% of our estimated total future development costs related to proved reserves. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. In addition, the development of these reserves will require the use of enhanced recovery techniques, including water flood and CO_2 injection installations, the success of which is less predictable than traditional development techniques. Therefore, ultimate recoveries from these fields may not match current expectations.

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

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

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 referred to in this prospectus supplement.

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, exploration and 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 referred to in this prospectus supplement. 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, as referred to in this prospectus supplement, is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements, we generally base the estimated discounted future net cash flows from our proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may differ materially from those used in the present value estimate. If natural gas prices decline by $0.10 per Mcf, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2008 would have decreased from

$1,376.4 million to $1,366.0 million. If oil prices decline by $1.00 per Bbl, then the standardized measure of discounted future net cash flows of our estimated proved reserves as of December 31, 2008 would have decreased from $1,376.4 million to $1,326.1 million.

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Our debt level and the covenants in the agreements governing our debt could negatively impact our financial condition, results of operations, cash flows and business prospects.

As of December 31, 2008, we had $620.0 million in borrowings and $2.8 million in letters of credit outstanding under Whiting Oil and Gas Corporation s credit agreement with $277.2 million of available borrowing capacity, as well as $620.0 million of senior subordinated notes outstanding. We are permitted to incur additional indebtedness, provided we meet certain requirements in the indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation s credit agreement.

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

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

We may be required to repay all or a portion of our debt on an accelerated basis in certain circumstances. If we fail to comply with the covenants and other restrictions in the agreements governing our debt, it could lead to an event of default and the acceleration of our repayment of outstanding debt. Our ability to comply with these covenants and other restrictions may be affected by events beyond our control, including prevailing economic and financial conditions. Moreover, the borrowing base limitation on Whiting Oil and Gas Corporation s credit agreement is periodically redetermined based on an evaluation of our reserves. Upon a redetermination, if borrowings in excess of the revised borrowing capacity were outstanding, we could be forced to repay a portion of our debt under the credit agreement.

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

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

The indentures governing our senior subordinated notes and Whiting Oil and Gas Corporation s credit agreement contain various restrictive covenants that may potentially limit our management s discretion in certain respects. In particular, these agreements will limit our and our subsidiaries ability to, among other things:

- pay dividends on, redeem or repurchase our capital stock or redeem or repurchase our subordinated debt;
- make loans to others;

- make investments;
- incur additional indebtedness or issue preferred stock;
- create certain liens;
- sell assets;
- enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us;
- consolidate, merge or transfer all or substantially all of the assets of us and our restricted subsidiaries taken as a whole;
- engage in transactions with affiliates;
- enter into hedging contracts;
- create unrestricted subsidiaries; and
- enter into sale and leaseback transactions.

In addition, Whiting Oil and Gas Corporation s credit agreement requires us to maintain a debt to EBITDAX ratio (as defined in the credit agreement) of less than 3.5 to 1 and a working capital ratio of greater than 1 to 1. Also, the indentures under which we issued our senior subordinated notes restrict us from incurring additional indebtedness, subject to certain exceptions, unless our fixed charge coverage ratio (as defined in the indentures) is at least 2.0 to 1. If we were in violation of this covenant, then we may not be able to incur additional indebtedness, including under Whiting Oil and Gas Corporation s credit agreement.

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

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

The oil and gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures in our business and operations for the exploration, development, production and acquisition of oil and 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 is subject to a number of variables, including:

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

- the prices at which oil and natural gas are sold; and
- our ability to acquire, locate and produce new reserves.

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

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

Our acquisition activities may not be successful.

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

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

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

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

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

Our business strategy includes a continuing acquisition program. From 2004 to 2008, we completed 13 separate acquisitions of producing properties for estimated proved reserves as of the effective dates of the acquisitions of 226.9 MMBOE. The successful acquisition of producing properties requires assessments of many factors, which are inherently inexact and may be inaccurate, including the following:

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

estimates of operating costs;

estimates of future development costs;

timing of future development costs;

estimates of the costs and timing of plugging and abandonment; and

potential environmental and other liabilities.

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.

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

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

The differential between the NYMEX or other benchmark price of oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

The prices that we receive for our oil and natural gas production generally trade at a discount to the relevant benchmark prices, such as NYMEX, that are used for calculating hedge positions. The difference between the benchmark price and the price we receive is called a differential. We cannot accurately predict oil and natural gas differentials. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could have a material adverse effect on our results of operations, financial condition and cash flows.

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

We are not insured against all risks. Losses and liabilities arising from uninsured and underinsured events could materially and adversely affect our business, financial condition or results of operations. Our oil and 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, 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 oil and gas, which could adversely affect the results of our drilling operations.

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

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

In connection with our continued development of oil and gas properties, we may be disproportionately exposed to the impact of delays or interruptions of production from wells in these properties, caused by transportation capacity constraints, curtailment of production or the interruption of transporting oil and gas volumes produced. In addition, market conditions or a lack of satisfactory oil and gas transportation arrangements may hinder our access to oil and gas markets or delay our production. The availability of a ready market for our oil and 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 substantially on the availability and capacity of gathering systems, pipelines and processing facilities owned and operated by third-parties. Additionally, entering into arrangements for these services exposes us to the risk that third parties will default on their obligations under such arrangements. Our failure to obtain such services on acceptable terms or the default by a third party on their obligation to provide such services could materially harm our business. We may be required to shut in wells for a lack of a market or because access to gas pipelines, gathering systems or processing facilities may be limited or unavailable. If that were to occur, then we would be unable to realize revenue from those wells until production arrangements were made to deliver the production to market.

We are subject to complex laws that can affect the cost, manner or feasibility