BERRY PETROLEUM CO
Form 424B3
May 15, 2009

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**The information in this preliminary prospectus supplement is not complete and may be changed. This preliminary prospectus supplement and the accompanying prospectus are not an offer to sell nor do they seek an offer to buy these securities in any jurisdiction where the offer or sale is not permitted.**

**SUBJECT TO COMPLETION, DATED MAY 15, 2009**

**Filed Pursuant to Rule 424(b)(3)**
**Registration No. 333-135055**

**PRELIMINARY PROSPECTUS SUPPLEMENT**

**(TO PROSPECTUS DATED FEBRUARY 26, 2009)**

# $300,000,000

# Berry Petroleum Company

## % Senior Notes due 2014

We are offering $300,000,000 of our % Senior Notes due 2014. Interest on the notes will accrue from May , 2009 and will be payable semiannually on May and November of each year, beginning on November , 2009. The notes will mature on May , 2014.

We may redeem some or all of the notes at a price equal to 100% of the principal amount plus accrued and unpaid interest plus a "make-whole" premium. If we sell certain of our assets or experience specific kinds of change of control, we must offer to purchase the notes at prices set forth in this prospectus supplement plus accrued and unpaid interest.

The notes will be our senior unsecured obligations. The notes will rank effectively junior to all of our existing and any future secured debt, to the extent of the value of the collateral securing that debt, will rank equally in right of payment with any future senior unsecured debt and will rank senior in right of payment to our existing $8^1/_4$% senior subordinated notes due 2016 and any of our other existing or future subordinated debt.

## You should consider carefully the risk factors beginning on page S-15 of this

**prospectus supplement before investing in the notes.**

| | Per Note | Total |
|---|---|---|
| Price to Public(1) | % | $ |
| Underwriting Discounts | % | $ |
| Proceeds to Berry Petroleum Company (Before Expenses) | % | $ |

(1) Plus accrued interest, if any, from May , 2009.

The notes will not be listed on any securities exchange. Currently, there is no public market for the notes. Delivery of the notes, in book-entry form, will be made on or about May , 2009 through The Depository Trust Company. See "Underwriting."

**Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or passed on the adequacy or accuracy of this prospectus. Any representation to the contrary is a criminal offense.**

*Joint Book-Running Managers*

**Wachovia Securities**

**RBS**

**BNP PARIBAS**

**SOCIETE GENERALE**

**CALYON**

*Senior Co-Managers*

**BMO Capital Markets** **Wedbush Morgan Securities Inc.**

*Co-Managers*

**BBVA Securities** **BOSC, Inc.** **Citi**
**Credit Suisse** **Natixis Bleichroeder Inc.**
**Raymond James** **Scotia Capital** **U.S. Bancorp Investments, Inc.**

**The date of this prospectus supplement is May , 2009.**

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**You should rely only on the information contained in this prospectus or to which the prospectus refers or that is contained in any free writing prospectus relating to the notes. We have not, and the underwriters have not, authorized anyone to provide you with different information. If anyone provides you with different or inconsistent information, you should not rely on it. We are not making an offer of the notes in any jurisdiction where their offer or sale is not permitted. The information in this prospectus supplement and the base prospectus and incorporated herein by reference may only be accurate as of the date of the applicable document. Our business, financial condition, results of operations and prospects may have changed since those dates.**

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This document is in two parts. The first part is this prospectus supplement, which describes the specific terms of the notes we are offering and certain other matters. The second part, the base prospectus dated February 26, 2009, provides more general information about the various securities that we may offer from time to time, some of which information may not apply to the notes we are offering hereby. Generally when we refer to this prospectus, we are referring to both this prospectus supplement and the base prospectus combined. If any of the information in this prospectus supplement is inconsistent with any of the information in the base prospectus, you should rely on the information in this prospectus supplement.

## Incorporation by Reference

The Securities and Exchange Commission ("SEC") allows us to "incorporate by reference" information we file with it. This means that we can disclose important information to you by referring you to those documents. Any information we reference in this manner is considered part of this prospectus. Information we file with the SEC after the date of this prospectus will automatically update and, to the extent inconsistent, supersede the information contained in this prospectus.

We incorporate by reference the documents listed below and future filings we make with the SEC pursuant to Sections 13(a), 13(c), 14 or 15(d) of the Securities Exchange Act of 1934, as amended (the "Exchange Act") after the date of this prospectus supplement and before the termination of this offering.

Our Annual Report on Form 10-K for the year ended December 31, 2008;

Our Definitive Proxy Statement filed on Schedule 14A relating to our 2009 Annual Meeting of Shareholders;

Our Quarterly Report on Form 10-Q for the quarter ended March 31, 2009;

Our Current Reports on Form 8-K and 8-K/A filed on September 29, 2008, January 12, 2009, January 26, 2009, February 20, 2009, March 23, 2009, April 27, 2009 and May 15, 2009; and

The description of our Class A Stock contained in our Registration Statement on Form 8-A which was declared effective by the SEC on or about October 20, 1987, and the description of our Rights to Purchase Series B Junior Participating Preferred Stock contained in our Registration Statement on Form 8-A filed with the SEC on December 7, 1999.

## Special Note Regarding Forward-Looking Statements

This prospectus supplement and the information incorporated by reference in this prospectus supplement and the accompanying prospectus contains statements that are, or may be deemed to be, "forward-looking statements" within the meaning of Section 27A of the Securities Act and Section 21E of the Securities Exchange Act of 1934, as amended. These statements relate to future events or our future financial performance. We have attempted to identify forward-looking statements by terminology such as "anticipate," "believe," "can," "continue," "could," "estimate," "expect," "intend," "may," "plan," "potential," "predict," "should," "would" or "will" or the negative of these terms or other comparable terminology. These statements are only predictions and involve known and unknown risks, uncertainties and other factors, including those discussed under "Risk Factors," which could cause our actual results to differ from those projected in any forward-looking statements we make.

We believe that it is important to communicate our future expectations to our investors. However, there may be events in the future that we are unable to accurately predict or control and that may cause our actual results to differ materially from the expectations we describe in our forward-looking statements. Forward-looking statements speak only as of the date of such statement. We do not plan to publicly update or revise any forward-looking statements after we distribute this prospectus, whether as a result of any new information, future events or otherwise. Potential investors should not place undue reliance on

our forward-looking statements. Before you invest in the notes, you should be aware that the occurrence of any of the events described in the "Risk Factors" section and elsewhere in this prospectus and the information incorporated by reference into this prospectus could harm our business, prospects, operations and financial condition. Although we believe that the expectations reflected in the forward-looking statements are reasonable, we cannot guarantee future results, levels of activity, performance or achievements.

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## PROSPECTUS SUPPLEMENT SUMMARY

*This summary highlights selected information contained elsewhere in this prospectus and in the documents we incorporate by reference. This summary is not complete and does not contain all of the information that you should consider before deciding whether or not to invest in the notes. For a more complete understanding of our company and this offering, we encourage you to read this entire document, including "Risk Factors," the financial and other information incorporated by reference in this prospectus and the other documents to which we have referred. Unless otherwise indicated or required by the context, as used in this prospectus, the terms "we," "our" and "us" refer to Berry Petroleum Company. Some of the oil and gas terms we use are defined under "Glossary of Oil and Natural Gas Terms." Unless otherwise indicated or required by the context, references to "pro forma" give effect to our July 2008 acquisition of properties in Limestone and Harrison Counties, Texas, as if the acquisition had occurred on January 1, 2008. DeGolyer and MacNaughton ("D&M"), independent petroleum engineers, provided the estimates of our proved oil and natural gas reserves as of December 31, 2006, 2007 and 2008, included in this prospectus supplement.*

***Berry Petroleum Company***

We are an independent energy company engaged in the production, development, exploitation and acquisition of crude oil and natural gas. We can trace our roots in California oil production back to 1909, and we have been a publicly traded company since 1987. Since 2002, we have expanded our portfolio of assets to include oil and natural gas properties in the Rocky Mountain region and, in 2008, the East Texas region. Our selective acquisitions have been driven by a consistent focus on properties with proved reserves and significant growth potential through low-risk development. We focus on growing reserves and production by developing known undeveloped reserves rather than through exploration. We maintain a geographically diverse portfolio of assets that generally have long reserve lives, stable and predictable well production characteristics and significant inventories of relatively low-risk repeatable drilling and recompletion opportunities. In April 2009, we sold our natural gas assets in the Denver-Julesburg basin in Colorado ("DJ Basin").

As of December 31, 2008, our estimated proved reserves were 246 MMBOE, up 45% from 169 MMBOE as of December 31, 2007, of which 51% were crude oil, 49% were natural gas and 55% were proved developed. The 88 MMBOE of net reserve additions before production in 2008 replaced 756% of our production during the year. Of such net reserve additions, 38 MMBOE, or 329% of our production, was replaced from our drilling activities. Our reserve replacement has been achieved through low cost and low risk drilling and acquisitions, with 2008 finding, development and acquisition ("F&D") costs of $12.28/BOE. See "  Non-GAAP Financial Measures  F&D Costs." We also achieved production of 32.0 MBOE/D in 2008, a 19% increase from 2007, which implies a reserve life index of approximately 21 years based on our year-end 2008 reserves.

Approximately 64% of our oil and natural gas sales volumes in 2008 were crude oil, with 82% of the crude oil being heavy oil produced in California. Our California reserves are characterized by long-lived predictable production with low base decline rates which provide us with strong margins and a steady source of cash flow. The cash flow from these properties funds our significant drilling inventory and the development of our substantial undeveloped reserves. Our consumption of natural gas to produce steam for our California oil production provides us with a natural hedge of approximately 26,000 MMBtu/D on our natural gas production in East Texas and Colorado. We have further protected our 2009 and 2010 cash flows through hedges on approximately 90% and 75% of our anticipated crude oil production for 2009 and 2010, respectively. Our strong hedge position, our ability to generate free cash flow and our operating control of 99% of our assets further enhances our ability to perform in volatile environments.

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***Operations Overview***

We have organized our operations into five asset teams as follows: South Midway Sunset, California, including our Poso Creek and Ethel D properties ("S. Midway"), North Midway Sunset, California, including our diatomite and Placerita oil assets ("N. Midway"), East Texas, Uinta, Utah and Piceance, Colorado. The following table sets forth the estimated quantities of proved reserves, production and acreage attributable to our principal operating areas for the periods indicated and shows the effect of the sale of our DJ Basin assets.

| | Proved Reserves as of December 31, 2008 | | | | Average Daily Production | | |
|---|---|---|---|---|---|---|---|
| **Operating Areas** | **Total (MMBOE)** | **% Oil** | **% Proved Developed** | **Average % Working Interest** | **Year Ended December 31, 2008 (MBOE/D)** | **Quarter Ended March 31, 2009 (MBOE/D)** | **Net Acreage** |
| S. Midway Sunset, CA | 64.9 | 100 | 74 | 98 | 11.9 | 11.4 | 3,087 |
| Uinta, UT | 23.3 | 65 | 47 | 98 | 6.2 | 5.4 | 36,635 |
| DJ Basin, CO | 21.5 | | 61 | 51 | 3.3 | 3.1 | 67,418 |
| N. Midway Sunset, CA | 44.4 | 100 | 44 | 100 | 4.7 | 5.1 | 2,235 |
| Piceance Basin, CO | 41.8 | | 32 | 41 | 3.5 | 3.3 | 3,157 |
| Limestone & Harrison Counties, TX | 50.0 | | 60 | 100 | 2.4(1) | 5.0 | 4,508 |
| Total | 245.9 | 51 | 55 | | 32.0(1) | 33.3 | 117,040 |
| Less: DJ Basin, CO(2) | 21.5 | | 61 | 51 | 3.3 | 3.1 | 67,418 |
| Pro Forma Total | 224.4 | 56 | 54 | | 28.7(1) | 30.2 | 49,622 |

(1) Includes production from the East Texas Assets, as defined below, from July 15, 2008 through December 31, 2008.

(2) Sold on April 1, 2009.

***California***

*S. Midway.* We own and operate properties in the South Midway Sunset Field. Production from our properties in the South Midway Sunset Field relies on thermal enhanced oil recovery ("EOR") methods, primarily cyclic steaming to place steam effectively into the remaining oil column. This is our most mature thermally enhanced asset with production from our Ethel D properties having commenced 100 years ago. We have planned a five-year, 150-well drilling program at Ethel D to develop the significant undeveloped reserves we believe are remaining on this asset. In 2008, we added 20 horizontal wells below existing horizontal wells at the South Midway Sunset Field, and we further developed Ethel D by drilling 32 producers and initiating a pilot steam flood. In 2009, we plan to drill ten additional, deeper horizontal wells, eight of which are now currently on production and performing in line with expectations. We also plan to evaluate the Ethel D steam flood pilot and reduce operating costs through optimization of well servicing and steam placement.

In early 2003, we acquired the Poso Creek properties in the San Joaquin Valley for approximately $3 million and have proceeded with a successful thermal EOR redevelopment. Average production from these properties increased from 1,950 Bbl/D in 2007 to 3,100 Bbl/D in 2008. In 2009, we expect production at Poso Creek to increase as the steam flood patterns we developed in 2008 continue to respond. We expect to focus our efforts in 2009 on improving steam-oil ratios and lowering operating expenses.

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*N. Midway.* In late 2006, we began the full-scale development of our N. Midway diatomite oil asset and have drilled 190 wells on this property. In 2008, total proved reserves and production from the N. Midway diatomite asset were 30.6 MBOE and 0.7 MBOE, respectively, representing an increase from 2007 of 162% in proved reserves and 86% in production. We expect significant proved reserve additions from this asset, where we are targeting ultimate recovery of oil in place of 23% with upside potential to 40%, which is comparable to other diatomite developments in California. In 2008, capital was focused on drilling approximately 85 diatomite wells, completing major infrastructure upgrades that will support future development, increasing steam injection and further refining our thermal recovery techniques. In 2009, we plan to invest $37 million to drill an additional 44 diatomite wells, 15 of which had been drilled as of March 31, 2009, and to install additional steam generation facilities. Diatomite production is expected to increase over 50% in 2009, averaging approximately 3,000 Bbl/D.

***East Texas***

On July 15, 2008, we acquired (the "East Texas Acquisition") certain interests in natural gas producing properties in the East Texas Cotton Valley on 4,500 net acres in Limestone and Harrison Counties in East Texas (the "East Texas Assets") for approximately $668 million in cash. The East Texas Assets included 140 producing natural gas wells as of March 31, 2009, and we have identified approximately 70 drilling locations targeting multi-zone stacked pay opportunities. The East Texas Assets established a core area in a prolific natural gas basin with a substantial inventory of repeatable drilling and recompletion projects from relatively low risk, multiple stacked reservoirs. In Limestone County, we are targeting seven productive sands including the Cotton Valley and Bossier sands at depths between 8,000 and 13,000 feet. In Harrison County, we are targeting five productive sands with average depths between 6,500 and 13,000 feet. We believe we have additional upside potential in the Haynesville and Bossier Shales. We executed a five rig program in 2008, and as of March 31, 2009, 23 wells have been drilled and put on production since acquiring the East Texas Assets. Production from our East Texas Assets averaged 31 MMcf/D and 30 MMcf/D in the fourth quarter of 2008 and the first quarter of 2009, respectively. We currently operate a one rig program and plan to begin drilling our first horizontal Haynesville well in Harrison County in the third quarter of 2009.

***Rockies***

*Uinta.* In 2003, we established our initial acreage position in the Uinta Basin, targeting the Green River formation that produces both light oil and natural gas. We acquired for approximately $45 million the Brundage Canyon leasehold in Duchesne County, northeastern Utah, which consists of working interests in approximately 55,000 undeveloped gross acres which include federal, tribal and private leases. In 2004, we acquired working interests in approximately 163,000 gross acres in the Lake Canyon project, which is located immediately west of our Brundage Canyon producing properties. Total production in Uinta averaged 6,142 BOE/D in 2008 compared to 5,743 BOE/D in 2007. Average daily production in Uinta during the three months ended March 31, 2009 was approximately 5,410 BOE/D. In 2008, we drilled 51 gross (50 net) wells, which included 47 wells at Brundage Canyon, including eight Ashley Forest wells, and four Green River wells at Lake Canyon. In 2009, capital is primarily directed at facility upgrades, pursuing the remaining three Lake Canyon completions and the completion of the Ashley Forest Environmental Impact Study.

*Piceance.* We have two properties in the Piceance Basin in Colorado targeting the Williams Fork section of the Mesaverde formation. We have a 50% working interest in 6,300 gross acres on our Garden Gulch property and a net operating working interest of 95% in 4,300 gross acres and a 5% non-operating working interest on 6,300 gross acres on our North Parachute Ranch property. We believe we have accumulated a sizable resource base with over 900 drilling locations which will allow us to add significant proved reserves over the next several years. Total production in Piceance averaged 20.8 MMcf/D in 2008 in comparison to 10.2 MMcf/D in 2007, and averaged 20.3 MMcf/D during the three months ended

March 31, 2009. We operated a four rig drilling program for most of 2008 and drilled 54 gross (27 net) wells at Garden Gulch and 18 gross (17 net) wells at North Parachute. Significant progress was made during 2008 in reducing the days required to drill wells. By the end of 2008, the number of drilling days averaged 10 days on Garden Gulch and 11 days in North Parachute, a 40% reduction in drilling times compared to early 2008. Our focus in 2009 will be on reducing our drilling and completion cost structure along with evaluating reservoir parameters and completion practices to improve ultimate recoveries. We currently have an inventory of approximately 44 completions and recompletions that we will be evaluating for supplemental capital expenditures should commodity prices warrant.

***Competitive Strengths***

*Balanced High Quality Asset Portfolio.* Since 2002, we have grown our asset base and diversified our California heavy oil assets through acquisitions in the Rocky Mountain and East Texas regions that have significant growth potential. Our diverse asset base provides us with the flexibility to reallocate capital among our assets depending on fluctuations in oil and natural gas prices as well as area economics.

*Long Lived Proved Reserves with Stable Production Characteristics.* Our properties generally have long reserve lives and reasonably stable and predictable well production characteristics with a ratio of proved reserves to production (based on the year ended December 31, 2008) of approximately 21 years.

*Low-Risk Multi-Year Drilling Inventory in Established Resource Plays.* Most of our drilling locations are located in proven resource plays that possess low geologic risk leading to predictable drilling results. Our California assets have an average depth of less than 1,500 feet and are located in areas where we are an established producer. Our East Texas Assets provide us with the opportunity for repeated development of multiple stacked reservoirs in the Travis Peak, Cotton Valley and Bossier sands. Our historical drilling success rate for the three years ended December 31, 2008 averaged 98%.

*Track Record of Efficient Proved Reserve and Production Growth.* For the three years ended December 31, 2008, our proved reserves and production increased at an annualized compounded rate of 25% and 12%, respectively. For example, our drilling and production efficiencies and selective acquisitions have allowed us to increase our California proved reserve inventory from 102 MMBOE as of December 31, 2002 to 109 MMBOE as of December 31, 2008 after cumulative production of 34.9 MMBOE during that period. We have achieved reserve replacement through low cost and low risk development drilling and acquisitions, with 2006, 2007 and 2008 F&D costs of $16.80/BOE, $12.47/BOE and $12.28/BOE, respectively. See " Non-GAAP Financial Measures F&D Costs."

*Operational Control and Financial Flexibility.* We have operating control over approximately 99% of our assets. We generally prefer to retain operating control over our properties, allowing us to more effectively control operating costs, timing of development activities and technological enhancements, marketing of production and allocation of our capital budget. In addition, the timing of most of our capital expenditures is discretionary, which allows us a significant degree of flexibility to adjust the size of our capital budget. We finance our drilling budget through our internally generated operating cash flows.

*Experienced Management and Operational Teams.* Our core team of technical staff and operating managers have broad industry experience, including experience in heavy oil thermal recovery operations and tight gas sands development and completion. We continue to utilize technologies and steam practices that we believe will allow us to improve the ultimate recoveries of crude oil on our mature California properties.

***Corporate Strategy***

Our objective is to increase the value of our business through consistent growth in our production and reserves, both through the drill-bit and acquisitions. We strive to operate our properties in an efficient manner to maximize the cash flow and earnings of our assets. The strategies to accomplish these goals include:

*Developing our Existing Resource Base.* We are focused on the timely and prudent development of our large resource base through developmental and step-out drilling, down-spacing, well completions, remedial work and by application of EOR methods and optimization technologies, as applicable. We believe we also have large undeveloped hydrocarbon reserves in place in diatomite (N. Midway), East Texas, Uinta and Piceance. We have a proven track record of developing reserves through enhanced recovery and establishing new businesses in the Rocky Mountain and East Texas regions. We continue to focus on low-risk development of our existing assets rather than exploration.

*Investing our Capital in a Disciplined Manner and Maintaining a Strong Financial Position.* We focus on utilizing our available capital on projects where we are likely to have success in increasing production and/or reserves at attractive returns. We believe that maintaining a strong financial position will allow us to capitalize on investment opportunities in all commodity cycles. Our capital programs are developed to be fully funded through internally generated cash flows. We hedge a significant portion of our production and utilize long-term sales contracts whenever possible to maintain a strong financial position and provide the cash flow necessary for the development of our assets. We have hedged approximately 90% and 75% of our anticipated crude oil production for 2009 and 2010, respectively.

*Accumulating Acreage Positions Near our Producing Operations.* We have been successful in expanding operations through targeted acreage acquisitions in our producing areas. This strategy allows us to leverage our operating and technical expertise within the area and build on established core operations. For example, we acquired our Poso Creek assets through three separate transactions for a total of $3 million beginning in 2003 and have successfully completed thermal EOR redevelopment to increase production from under 50 Bbl/D at acquisition to 3,100 Bbl/D in 2008.

*Acquiring Additional Assets with Significant Growth Potential.* We will continue to evaluate oil and natural gas properties with proved reserves, probable reserves and/or acreage positions that we believe contain substantial hydrocarbons which can be developed at reasonable costs. We will continue to review asset acquisitions that meet our economic criteria with a primary focus on large repeatable development potential in these regions.

***Recent Developments***

We have successfully taken several actions in recent months to further enhance our liquidity and financial flexibility.

*Sale of DJ Basin Assets.* On March 3, 2009, we entered into an agreement to sell our DJ Basin assets and related hedges for $154 million before customary closing adjustments. We completed the sale of our DJ Basin related hedges in March 2009 for approximately $14 million and closed the sale of our DJ Basin assets on April 1, 2009 for approximately $140 million. The DJ Basin assets represented essentially all of our assets in Northeastern Colorado. These assets included natural gas reserves, mid-stream assets and an associated natural gas hedge valued at $14 million. Production from the property was approximately 3,101 BOE/D for the three months ended March 31, 2009 and, as of December 31, 2008, the property represented 21.5 MMBOE of our proved reserves. Proceeds of the sale were used to repay a portion of our borrowings outstanding under our senior secured revolving credit facility pending utilization as part of our working capital.

*Borrowing Base Redetermination and Second Lien Term Loan.* On April 27, 2009, we completed the scheduled redetermination of the borrowing base under our senior secured revolving credit facility and entered into a $140 million second lien term loan, which matures on January 16, 2013. Our borrowing base was set at $1.0 billion. Proceeds from the second lien term loan were used to repay a portion of our

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borrowings under our senior secured revolving credit facility. On April 27, 2009, following the closing of the second lien term loan, the outstanding amount under our senior secured revolving credit facility was approximately $735 million, providing us with approximately $275 million of liquidity.

The net proceeds from this offering will be used to repay in full the second lien term loan and reduce outstanding borrowings under our senior secured revolving credit facility. After giving effect to this offering and those repayments, we expect that our borrowing base will be reduced to $933 million and that we will have $ million in outstanding borrowings under our senior secured revolving credit facility, providing us with approximately $ million in liquidity under that facility. For more information regarding our outstanding debt, please read "Description of Other Indebtedness."

***Executive Offices and Website***

We were incorporated in Delaware in 1985. Our corporate headquarters and principal executive offices are located at 1999 Broadway, Suite 3700, Denver, Colorado 80202, and our telephone number is (303) 999-4400. We maintain a web site at *http://www.bry.com*. The information on our website is not part of this prospectus, and you should rely only on the information contained in this prospectus and in the documents incorporated by reference when making a decision as to whether to invest in the notes.

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## The Offering

The following summary contains basic information about the notes and is not intended to be complete. For a more complete understanding of the notes, please refer to the section entitled "Description of Notes" beginning on page S-38 in this prospectus supplement.

| | |
|---|---|
| **Issuer** | Berry Petroleum Company |
| **Securities offered** | $300,000,000 aggregate principal amount of % Senior Notes due 2014 |
| **Maturity** | May , 2014 |
| **Interest payment dates** | May and November , commencing November , 2009 |
| **Make-whole redemption** | We may redeem some or all of the notes at a price equal to 100% of the principal amount of the notes plus accrued and unpaid interest, if any, plus a "make-whole" premium described in "Description of Notes Optional redemption." |
| **Mandatory offers to purchase** | If a specified change of control event occurs, we must make an offer to purchase the notes at a purchase price of 101% of the principal amount of the notes, plus accrued and unpaid interest, if any, to the date of the purchase. See "Description of Notes Change of control."<br>Certain asset dispositions will be triggering events that may require us to use the net proceeds from those asset dispositions to make an offer to purchase the notes at 100% of their principal amount, together with accrued and unpaid interest, if any, to the date of purchase if such proceeds are not otherwise used within 330 days to repay certain types of indebtedness (with a corresponding permanent reduction in commitment, if applicable) or to invest in capital assets or capital expenditures related to our business. See "Description of Notes Certain covenants Limitation on sales of assets and subsidiary stock." |
| **Ranking** | The notes will be our unsecured senior obligations. The notes will rank:<br>effectively junior to all of our existing and future senior secured indebtedness, including our senior secured revolving credit facility and our senior secured money market line of credit;<br>equally in right of payment with any future senior unsecured indebtedness; and<br>senior in right of payment to all of our existing and any future subordinated indebtedness and obligations.<br>As of March 31, 2009, after giving pro forma effect to this offering, the application of net proceeds therefrom and the application of the net proceeds of the sale of our DJ Basin assets, the notes would have ranked effectively junior to approximately $ million of senior secured indebtedness and senior to $200 million of our $8^1/_4$% senior subordinated notes due 2016 ("$8^1/_4$% senior subordinated notes"). See "Description of Notes Ranking." |

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| | |
|---|---|
| **Covenants** | We will issue the notes under an indenture with Wells Fargo Bank, National Association, as trustee. The indenture will, among other things, limit our ability and the ability of our future restricted subsidiaries to:<br>incur, assume or guarantee additional indebtedness or issue redeemable stock;<br>pay dividends or distributions or redeem or repurchase capital stock;<br>prepay, redeem or repurchase debt that is junior in right of payment to the notes;<br>make loans and other types of investments;<br>incur liens;<br>restrict dividends, loans or asset transfers from our subsidiaries;<br>sell or otherwise dispose of assets, including capital stock of subsidiaries;<br>consolidate or merge with or into, or sell substantially all of our assets to, another person;<br>enter into transactions with affiliates; and<br>enter into new lines of business.<br>These covenants are subject to important exceptions and qualifications, which are described under the caption "Description of Notes  Certain covenants." In addition, if and for as long as the notes have an investment grade rating from both Standard & Poor's Ratings Group, Inc. and Moody's Investors Service, Inc., and no default exists under the indenture, we will not be subject to certain of the covenants listed above. |
| **Original issue discount** | The notes will be issued with original issue discount for United States federal income tax purposes. Such original issue discount will accrue from the issue date of the notes and will be included as interest income periodically in a U.S. holder's gross income for United States federal income tax purposes in advance of receipt of the cash payments to which such income is attributable, regardless of the holders' method of accounting. Please see "Certain United States Federal Tax Considerations  Consequences to U.S. Holders  Original Issue Discount." |
| **Use of proceeds** | We intend to use the net proceeds from this offering to repay in full our second lien term loan and a portion of our current borrowings under our senior secured revolving credit facility. See "Use of Proceeds." |

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**Summary Historical and Pro Forma Financial Data**

The following table shows our summary historical financial data as of and for the periods indicated and summary pro forma financial data as of and for the year ended December 31, 2008. Our summary historical financial data are derived from our unaudited financial statements and, in our opinion, have been prepared on the same basis as the audited financial statements and include all adjustments, consisting of normal recurring adjustments, necessary for a fair presentation of this information. Certain historical amounts have been reclassified to conform to the current presentation. On May 17, 2006, a two-for-one stock split was approved. All per share amounts have been adjusted for the split.

The unaudited financial data set forth below with respect to the fiscal years ended December 31, 2006, 2007 and 2008 have been revised from the presentation in our audited financial statements for such periods to reflect (1) the presentation as discontinued operations of our DJ Basin assets, which were sold on April 1, 2009, in accordance with Statement of Financial Accounting Standards (SFAS) No. 144, "*Accounting for the Impairment or Disposal of Long-Lived Assets*," and (2) our implementation of *FASB Staff Position No. EITF 03-06-1, Determining Whether Instruments Granted in Share-Based Payment Transactions Are Participating Securities*, which requires the revision of prior period basic and diluted earnings per share data. For more information, please read our audited financial statements as of December 31, 2007 and 2008 and for the fiscal years ended December 31, 2006, 2007 and 2008 included in our Annual Report on Form 10-K for the year ended December 31, 2008. These revisions will be reflected in our audited financial statements included in our Annual Report on Form 10-K for the year ended December 31, 2009 and any registration statement we file with the SEC prior to filing such Annual Report.

The summary pro forma financial data set forth below is derived from our unaudited pro forma financial statements included in our Current Report on Form 8-K filed with the SEC on May 15, 2009. The summary pro forma financial data combines the East Texas Assets operations, which were acquired on July 15, 2008, and our historical statements of operations, and gives effect to the East Texas Acquisition, including the payment of the expenses related to the East Texas Acquisition, and the sale of our DJ Basin assets, which was completed on April 1, 2009.

You should read the summary historical and pro forma financial data below in conjunction with our historical and pro forma financial statements and the accompanying notes, all of which are incorporated by reference into this prospectus. You should also read the sections entitled "Risk Factors" included elsewhere in this prospectus and "Management's Discussion and Analysis of Financial Condition and Results of Operations" included in our Annual Report on Form 10-K for the year ended December 31, 2008 and our Quarterly Report on Form 10-Q for the period ended March 31, 2009.

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| ($ in thousands, except ratios and earnings per share) | Historical | | | | | Pro Forma |
|---|---|---|---|---|---|---|
| | Year Ended December 31, | | | Three Months Ended March 31, | | Year Ended December 31, |
| | 2006 | 2007 | 2008 | 2008 | 2009 | 2008 |
| **Statement of operations data:** | | | | | | |
| **Revenues:** | | | | | | |
| Sales of oil and natural gas | $ 396,497 | $ 433,208 | $ 649,248 | $ 151,666 | $ 127,869 | $ 695,779 |
| Sales of electricity | 52,932 | 55,619 | 63,525 | 15,927 | 10,270 | 63,525 |
| Gas marketing | | | 35,750 | 3,231 | 7,581 | 35,750 |
| Gain on derivative terminations | | | | | 14,270 | |
| Gain (loss) on ineffective commodity derivatives | | | | (708) | 22,894 | |
| Gain (loss) on sales of assets | 103 | 54,173 | (1,297) | | | (1,297) |
| Interest and other income, net | 1,462 | 4,414 | 3,504 | 830 | 283 | 3,504 |
| Total revenues | $ 450,994 | $ 547,414 | $ 750,730 | $ 170,946 | $ 183,167 | $ 797,261 |
| **Expenses:** | | | | | | |
| Operating costs oil and natural gas production | $ 111,490 | $ 130,940 | $ 188,758 | 39,340 | $ 37,384 | $ 189,872 |
| Operating costs electricity generation | 48,281 | 45,980 | 54,891 | 16,399 | 8,783 | 54,891 |
| Production taxes | 12,169 | 14,651 | 26,876 | 5,183 | 5,652 | 30,599 |
| Depreciation, depletion and amortization oil and natural gas production | 61,419 | 82,861 | 125,595 | 24,207 | 36,398 | 135,046 |
| Depreciation, depletion and amortization electricity generation | 3,343 | 3,568 | 2,812 | 693 | 959 | 2,812 |
| Natural gas marketing | | | 32,072 | 2,982 | 7,284 | 32,072 |
| General and administrative expenses | 36,474 | 39,663 | 54,279 | 11,132 | 13,294 | 56,955 |
| Commodity derivatives | (736) | (13) | 213 | | | 213 |
| Dry hole, abandonment, impairment and exploration | 9,754 | 8,351 | 10,543 | 2,728 | 122 | 10,543 |
| Bad debt expense | | | 38,665 | | | 38,665 |
| Total expenses | $ 282,194 | $ 326,001 | $ 534,704 | $ 102,664 | $ 109,876 | $ 551,668 |
| Income from continuing operations before interest and income taxes | $ 168,800 | $ 221,413 | $ 216,026 | $ 68,282 | $ 73,291 | $ 245,593 |
| Interest expense | 8,894 | 15,069 | 23,942 | 3,327 | 10,050 | 48,397 |
| Income from continuing operations before provision for income taxes | $ 159,906 | $ 206,344 | $ 192,084 | $ 64,955 | $ 63,241 | $ 197,196 |
| Provision for income taxes | 62,049 | 79,060 | 70,308 | 25,419 | 21,462 | 71,279 |
| Income from continuing operations | 97,857 | 127,284 | 121,776 | 39,536 | 41,779 | 125,917 |
| Income (loss) from discontinued operations, net of taxes | 10,086 | 2,644 | 11,753 | 3,495 | (6,781) | 11,753 |
| Net income | $ 107,943 | $ 129,928 | $ 133,529 | $ 43,031 | $ 34,998 | $ 137,670 |
| Basic net income from continuing operations per share | $ 2.21 | $ 2.85 | $ 2.70 | $ 0.88 | $ 0.92 | $ 2.79 |
| Basic net income (loss) from discontinued operations per share | $ 0.23 | $ 0.06 | $ 0.26 | $ 0.08 | $ (0.15) | $ 0.26 |
| Basic net income per share | $ 2.44 | $ 2.91 | $ 2.96 | $ 0.96 | $ 0.77 | $ 3.05 |
| Diluted net income from continuing operations per share | $ 2.18 | $ 2.81 | $ 2.66 | $ 0.86 | $ 0.92 | $ 2.75 |
| Diluted net income (loss) from discontinued operations per share | $ 0.22 | $ 0.06 | $ 0.26 | $ 0.08 | $ (0.15) | $ 0.26 |
| Diluted net income per share | $ 2.40 | $2.87 | $ 2.92 | $ 0.94 | $ 0.77 | $ 3.01 |
| Cash dividends declared per common share | 0.30 | 0.30 | 0.30 | 0.075 | 0.075 | .30 |
| **Balance sheet data (as of period end):** | | | | | | |
| Cash and cash equivalents | $ 416 | $ 316 | $ 240 | $ 2,679 | $ 49 | |

| | | | | | |
|---|---|---|---|---|---|
| Working capital | (116,594) | (110,350) | (71,545) | (123,248) | 168,691 |
| Oil and natural gas properties, buildings and equipment, net | 1,080,631 | 1,275,091 | 2,254,425 | 1,333,578 | 2,096,593 |
| Total assets | 1,198,997 | 1,452,106 | 2,542,383 | 1,524,129 | 2,492,629 |
| Bank debt | 206,000 | 259,300 | 957,100 | 255,200 | 999,400 |
| 8 1/4% subordinated notes | 200,000 | 200,000 | 200,000 | 200,000 | 200,000 |
| Shareholders' equity | 427,700 | 459,974 | 827,544 | 461,080 | 812,559 |
| **Cash flows data:** | | | | | |
| Net cash flow provided by (used in): | | | | | |
| Operating activities | $ 258,475 | $ 238,879 | $ 409,569 | $ 87,235 | $ 8,129 |
| Investing activities | (548,783) | (287,213) | (1,086,76) | (79,715) | (42,666) |
| Financing activities | 288,734 | 48,234 | 677,124 | (5,157) | 34,346 |
| **Other financial data:** | | | | | |
| EBITDAX(1) | $ 243,316 | $ 316,193 | $ 354,976 | $ 95,910 | $ 110,770 |
| Exploration and development of oil and natural gas properties | 265,110 | 281,702 | 392,769 | 75,869 | 49,898 |
| Property acquisitions | $ 257,840 | $ 56,247 | $ 667,996 | $ 261 | $ 1,173 |

(1) Before income (loss) from discontinued operations. See " Non-GAAP Financial Measures EBITDAX."

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## Non-GAAP Financial Measures

### *EBITDAX*

We define EBITDAX as net income before interest expense, provision for income taxes and depreciation, depletion, amortization, dry hole, abandonment, impairment and exploration expense (from both continuing and discontinued operations) and income or loss from discontinued operations. EBITDAX is a financial measure commonly used in the oil and gas industry, but is not defined under accounting principles generally accepted in the United States of America ("GAAP"). EBITDAX should not be considered in isolation or as a substitute for net income, operating income, cash flows from operating activities or any other measure of financial performance presented in accordance with GAAP or as a measure of a company's profitability or liquidity. Because EBITDAX excludes some, but not all, items that affect net income, this measure may vary among companies. The EBITDAX data presented below may not be comparable to a similarly titled measure of other companies. Our management believes that EBITDAX is a useful comparative measure of operating performance. For example, debt levels, credit ratings and, therefore, the impact of interest expense on earnings vary significantly between companies. Similarly, the tax positions of individual companies can vary because of their differing abilities to take advantage of tax benefits, with the result that their effective tax rates and tax expense can vary considerably. Finally, companies differ in the age and method of acquisition of productive assets, and thus the relative costs of those assets, as well as in the depreciation or depletion (straight-line, accelerated, units of production) method, which can result in considerable variability in depletion, depreciation and amortization expense between companies. Thus, for comparison purposes, management believes that EBITDAX can be useful as an objective and comparable measure of operating profitability and the contribution of operations to liquidity because it excludes these elements.

The following table provides a reconciliation of net income to EBITDAX:

| | Historical | | | | |
|---|---|---|---|---|---|
| | Year Ended December 31, | | | Three Months Ended March 31, | |
| **($ in thousands)** | **2006** | **2007** | **2008** | **2008** | **2009** |
| Net income | $107,943 | $129,928 | $133,529 | $43,031 | $ 34,998 |
| Provision for income taxes | 62,049 | 79,060 | 70,308 | 25,419 | 21,462 |
| Interest expense | 8,894 | 15,069 | 23,942 | 3,327 | 10,050 |
| Depreciation, depletion and amortization | 64,762 | 86,429 | 128,407 | 24,900 | 37,357 |
| Dry hole, abandonment, impairment and exploration expense | 9,754 | 8,351 | 10,543 | 2,728 | 122 |
| Less: | | | | | |
| Income (loss) from discontinued operations | 10,086 | 2,644 | 11,753 | 3,495 | (6,781) |
| EBITDAX | $243,316 | $316,193 | $354,976 | $95,910 | $110,770 |

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***F&D Costs***

The following table reflects a reconciliation of our F&D costs for the years ended December 31, 2006, 2007 and 2008 to the information required by paragraphs 11 and 21 of Statement of Financial Accounting Standard No. 69. F&D costs are computed by dividing the sum of property acquisition costs, development and exploration costs for the year, by total reserve additions, excluding production, for the year.

| **(in millions)** | **2006** | **2007** | **2008** |
|---|---|---|---|
| Property acquisition costs | $257,840 | $ 56,247 | $ 667,996 |
| Development | 277,613 | 278,398 | 385,599 |
| Exploration | 22,435 | 23,325 | 32,909 |
| Costs incurred in oil and natural gas producing activities | $557,888 | $357,970 | $1,086,504 |
| Total reserves added, excluding production (MMBOE) | 33.2 | 28.7 | 88.5 |
| Estimated F&D cost per BOE | $ 16.80 | $ 12.47 | $ 12.28 |

Our management believes that providing a measure of F&D costs is useful to assist in an evaluation of how much it costs us, on a per BOE basis, to add proved reserves. However, these measures are provided in addition to, and not as an alternative for, and should be read in conjunction with, the information contained in our financial statements prepared in accordance with GAAP (including the notes thereto) included in our Annual Report on Form 10-K for the year ended December 31, 2008. Due to various factors, including timing differences, F&D costs do not necessarily reflect precisely the costs associated with particular reserves. For example, development costs may be recorded in periods subsequent to the periods in which related increases in reserves are recorded. In addition, changes in commodity prices can affect the magnitude of recorded increases in reserves independent of the related costs of such increases.

As a result of the foregoing factors and various factors that could materially affect the timing and amounts of future increases in reserves and the timing and amounts of future costs, including factors disclosed in our filings with the SEC, we cannot assure you that our future F&D costs will not differ materially from those set forth above.

The methods we use to calculate our F&D costs may differ significantly from methods used by other companies to compute similar measures. As a result, our F&D costs may not be comparable to similar measures provided by other companies.

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**Summary Historical Reserve, Production and Operating Data**

Historical estimates of our oil and natural gas reserves and present values as of and for our fiscal years ended December 31, 2006, 2007 and 2008 are derived from reserve reports prepared by D&M. Estimates of reserves and their value are inherently imprecise and are subject to constant revision and change, and they should not be construed as representing the actual quantities of future production or cash flows to be realized from oil and natural gas properties or the fair market value of such properties.

The following table sets forth summary data with respect to estimated proved reserves on a historical basis and on a pro forma basis for the sale of our DJ Basin assets as of and for the periods presented:

| | Historical | | | Pro Forma for DJ Basin Asset Sale(1) |
|---|---|---|---|---|
| | As of December 31, | | | As of December 31, |
| **($ in thousands)** | **2006** | **2007** | **2008** | **2008** |
| **Proved reserves:** | | | | |
| Crude oil (MBbl) | 112,538 | 116,602 | 125,251 | 125,251 |
| Natural gas (MMcf) | 226,363 | 315,464 | 724,135 | 595,281 |
| Total (MBOE) | 150,262 | 169,179 | 245,940 | 224,464 |
| % oil | 75% | 70% | 51% | 56% |
| % proved developed | 68% | 61% | 55% | 54% |
| Reserve life (years)(2) | 16.2 | 17.2 | 21.0 | 21.4 |
| Undiscounted future net cash flows | $2,293,207 | $4,837,388 | $2,756,343 | N/A |
| Standardized measure of discounted future net cash flows(3) | $1,182,268 | $2,419,506 | $1,135,581 | N/A |

(1) Gives effect to the DJ Basin asset sale only. Information related to the East Texas Assets is included in the historical information as of December 31, 2008.

(2) Reserve life is a measure of the productive life of oil and natural gas properties, expressed in years. Reserve life is calculated by dividing proved reserve volumes at year end by production for the year shown.

(3) Standardized measure is the present value of estimated future net revenue to be generated from the production of proved reserves, determined in accordance with the rules and regulations of the SEC (using prices and costs in effect as of the date of estimation), less future development, production and income tax expenses, and discounted at 10% per annum to reflect the timing of future net revenue. Standardized measure does not give effect to derivative transactions. For a description of our derivative transactions, please read "Management's Discussion and Analysis of Financial Condition and Results of Operation Quantitative and Qualitative Disclosure about Market Risk" in our Annual Report on Form 10-K for the year ended December 31, 2008.

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***End of Period Prices***

In accordance with SEC requirements, our estimated net proved reserves and standardized measure were determined using end of the period prices for oil and natural gas that were realized at the date set forth below. The reserve estimates utilized the following realized wellhead prices for the dates presented:

| | As of December 31, | | |
|---|---|---|---|
| | **2006** | **2007** | **2008** |
| Oil ($/Bbl) | $46.15 | $79.19 | $30.03 |
| Natural gas ($/Mcf) | 4.45 | 6.27 | 4.85 |
| BOE Price | 41.23 | 66.27 | 30.92 |

***Historical Production and Operating Data***

The following table sets forth summary data with respect to production data and effective unit prices on a historical basis for the periods presented and gives effect to the sale of our DJ Basin assets:

| | Year Ended December 31, | | | Three Months Ended March 31, | |
|---|---|---|---|---|---|
| | **2006** | **2007** | **2008** | **2008** | **2009** |
| **Production data:** | | | | | |
| Crude oil (Bbl/D) | 19,679 | 19,753 | 20,330 | 19,885 | 19,502 |
| Natural gas (Mcf/D) | 34,317 | 42,895 | 69,834 | 49,086 | 82,979 |
| Total production (BOE/D) | 25,398 | 26,902 | 31,968 | 28,066 | 33,332 |
| DJ Basin Production (BOE/D) | 2,679 | 3,123 | 3,295 | 3,157 | 3,101 |
| Production Continuing operations (BOE/D) | 22,719 | 23,779 | 28,673 | 24,909 | 30,231 |
| **Effective unit prices before the impact of hedges:** | | | | | |
| Crude oil (Bbl) | $ 52.92 | $ 57.85 | $ 86.90 | $ 88.42 | $ 32.69 |
| Natural gas (Mcf) | 5.21 | 4.17 | 6.91 | 7.62 | 3.88 |
| Average sales price before hedging (BOE) | $ 50.01 | $ 52.30 | $ 73.64 | $ 75.11 | $ 29.36 |
| **Effective unit prices including impact of hedges:** | | | | | |
| Crude oil (Bbl) | $ 50.55 | $ 53.24 | $ 70.01 | $ 72.82 | $ 56.48 |
| Natural gas (Mcf) | 5.38 | 5.48 | 7.11 | 7.43 | 5.02 |
| Average sales price after hedging (BOE) | $ 48.09 | $ 49.80 | $ 62.03 | $ 62.44 | $ 47.11 |
| **Operating expenses per BOE:** | | | | | |
| Operating costs oil and natural gas production | $ 13.45 | $ 15.09 | $ 17.99 | $ 17.36 | $ 13.74 |
| Production taxes | 1.47 | 1.69 | 2.56 | 2.29 | 2.08 |
| DD&A oil and natural gas production | 7.41 | 9.55 | 11.97 | 10.68 | 13.38 |
| G&A | 4.40 | 4.57 | 5.17 | 4.91 | 4.89 |
| Interest expense | 1.07 | 1.74 | 2.28 | 1.47 | 3.69 |
| Total | $ 27.80 | $ 32.64 | $ 39.97 | $ 36.71 | $ 37.78 |

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## RISK FACTORS

You should carefully consider the risks described below, as well as other information included or incorporated by reference in this prospectus supplement, before making an investment decision. The risks and uncertainties described below are not the only ones we face. Additional risks and uncertainties not presently known to us or that we currently deem immaterial may also impair our business operations. If any of the following risks actually occurs, our business, financial condition or results of operations could be materially adversely affected, which in turn could adversely affect our ability to pay interest and/or principal on the notes.

***Risks Related to our Business***

***Oil and natural gas prices fluctuate widely, and low prices for an extended period of time are likely to have a material adverse impact on our business, results of operations and financial condition.***

Our revenues, profitability and future growth and reserve calculations depend substantially on the price received for our oil and natural gas production. These prices also affect the amount of our cash flow available for capital expenditures, working capital and payments on our debt and payments on the notes and our ability to borrow and raise additional capital. Lower prices may also reduce the amount of oil and natural gas that we can produce economically. The oil and natural gas markets fluctuate widely, and we cannot predict future oil and natural gas prices. Commodity prices were extremely volatile in 2008, with WTI crude ranging from a high of $145.29 per barrel to a low of $33.87 per barrel, while Henry Hub natural gas has ranged from a high of $13.58 per Mcfe to a low of $5.29 per Mcfe. Prices for oil and natural gas may fluctuate widely in response to relatively minor changes in the supply of and demand for oil and natural gas, market uncertainty and a variety of additional factors that are beyond our control, such as:

- regional, domestic and foreign supply and perceptions of supply of and demand for oil and natural gas;
- level of consumer demand;
- weather conditions;
- overall domestic and global political and economic conditions;
- technological advances affecting energy consumption and supply;
- domestic and foreign governmental regulations and taxation;
- the impact of energy conservation efforts;
- the capacity, cost and availability of oil and natural gas pipelines and other transportation facilities; and
- the price and availability of alternative fuels.

Our revenue, profitability and cash flow depend upon the prices and demand for oil and natural gas, and a drop in prices can significantly affect our financial results and impede our growth. In particular, declines in commodity prices:

- reduce the amount of cash flow available to make capital expenditures or make acquisitions;

reduce the number of our drilling locations;

increase the likelihood of refinery default;

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- negatively impact the value of our reserves, because declines in oil and natural gas prices would reduce the amount of oil and natural gas that we can produce economically; and

- limit our ability to borrow money or raise additional capital.

***Our heavy crude oil in California may be less economic than lighter crude oil and natural gas.***

As of December 31, 2008, approximately 45% of our proved reserves, or 109 million barrels, consisted of heavy oil. Light crude oil represented 6% and natural gas represented 49% of our oil and natural gas reserves. Heavy crude oil sells for a discount to light crude oil, as more complex refining equipment is required to convert heavy oil into high value products. Additionally, most of our crude oil in California is produced using the enhanced oil recovery process of steam injection. This process is generally more costly than primary and secondary recovery methods.

***Purchasers of our crude oil and natural gas may become insolvent.***

We have significant concentrations of credit risk with the purchasers of our crude oil and natural gas. We had a long-term contract to sell all of our heavy crude oil in California for approximately $8.10 below WTI with Big West of California ("BWOC"). On December 22, 2008, Flying J, Inc. and its wholly owned subsidiary Big West Oil and its wholly owned subsidiary BWOC each filed for bankruptcy protection under Chapter 11 of the United States Bankruptcy Code. Also in December 2008, BWOC informed us that it was unable to receive our production. On March 17, 2009, we entered into a stipulation with BWOC, terminating the contract effective as of March 16, 2009. We recorded $38.5 million of bad debt expense in 2008 for the bankruptcy of BWOC. Of the $38.5 million due from BWOC, $11.8 million represents 20 days of our December crude oil sales and an administrative claim under the bankruptcy proceedings and $26.7 million represents November and the balance of December crude oil sales which would have the same priority as other general unsecured claims. BWOC will also be liable to us for damages under this contract. While we also have guarantees from Big West Oil and from Flying J, Inc. in the amount of $75 million each, the information received from the bankruptcy proceedings to date has not provided us with adequate data from which to make a conclusion that any amounts will be collected. We have entered into various short-term agreements with other companies to sell our California oil production.

Additionally, all of our crude oil in Utah is sold under a long-term contract to a single refiner. Under the standard credit terms with our refiners, we may not know that a refiner will be unable to make payment to us until 50 days of our production has been delivered to them. If our purchasers become insolvent, we may not be able to collect any of the amounts owed to us.

***We may be unable to meet our drilling obligations.***

We have drilling obligations in both the Piceance assets in Colorado and our Lake Canyon asset in Utah. In the Piceance basin, we must drill 91 additional wells by February 2011 to avoid penalties of $0.2 million per well and the loss of related leases. In Lake Canyon, we must drill an additional seven wells by November 2009 to avoid the loss of related leases. Our ability to meet these commitments depends on the capital resources available to us to fund our drilling activities and the commodity price environment which affects the economics of these projects.

***Our financial counterparties may be unable to satisfy their obligations.***

We rely on financial institutions to fund their obligations under our senior secured revolving credit facility and make payments to us under our hedging agreements. If one or more of our financial counterparties becomes insolvent, they may not be able to meet their commitment to fund future borrowings under our credit facility which would reduce our liquidity. Additionally, at current commodity prices, a significant portion of our cash flow over the next two years would come from payments from our counterparties on our commodity hedging contracts. If our counterparties are not able to make these payments, our cash flow will be reduced.

***A widening of commodity differentials may adversely impact our revenues and our economics.***

Our crude oil and natural gas are priced in the local markets where the production occurs based on local or regional supply and demand factors. The prices that we receive for our crude oil and natural gas production are generally lower than the relevant benchmark prices, such as NYMEX, that are used for calculating commodity derivative positions. The difference between the benchmark price and the price we receive is called a differential. We may not be able to accurately predict natural gas and crude oil differentials.

Price differentials may widen in the future. Numerous factors may influence local pricing, such as refinery capacity, pipeline capacity and specifications, upsets in the mid-stream or downstream sectors of the industry, trade restrictions and governmental regulations. We may be adversely impacted by a widening differential on the products we sell. Our oil and natural gas hedges are based on WTI or natural gas index prices, so we may be subject to basis risk if the differential on the products we sell widens from those benchmarks and we do not have a contract tied to those benchmarks. Additionally, insufficient pipeline capacity or trucking capability and the lack of demand in any given operating area may cause the differential to widen in that area compared to other oil and natural gas producing areas. Increases in the differential between the benchmark price for oil and natural gas and the wellhead price we receive could adversely affect our financial condition.

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

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

***We may not be able to deliver minimum crude oil volumes required by certain sales contracts.***

Production volumes from our Uinta properties over the next five years are uncertain and there is no assurance that we will be able to consistently meet the minimum contractual requirement. After partial completion of its refinery expansion in Salt Lake City in March 2008, the refiner increased its total purchased volumes to 5,000 Bbl/D. During the term of the contract, the minimum number of delivered barrels is 5,000 Bbl/D. In the event that we cannot produce the necessary volume, we may need to purchase crude oil to meet our contract requirements. Current gross oil production from our Uinta properties is approximately 3,280 Bbl/D in the first three months of 2009.

***We may be subject to the risk of adding additional steam generation equipment if the electrical market deteriorates significantly.***

We are dependent on several cogeneration facilities that, combined, provide approximately 32% of our steam capacity as of December 31, 2008. These facilities are dependent on reasonable power contracts

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for the sale of electricity. If, for any reason, including if utilities that purchase electricity from us are no longer required by regulation to enter into power contracts with us, we were unable to enter into new or replacement contracts or were to lose any existing contract, we may not be able to supply 100% of the steam requirements necessary to maximize production from our heavy oil assets. An additional investment in various steam sources may be necessary to replace such steam, and there may be risks and delays in being able to install conventional steam equipment due to permitting requirements and availability of equipment. The financial cost and timing of such new investment may adversely affect our production, capital outlays and cash provided by operating activities. All of our power contracts covering our electricity generation expire in 2009.

***The future of the electricity market in California is uncertain.***

We utilize cogeneration plants in California to generate lower cost steam compared to conventional steam generation methods. Electricity produced by our cogeneration plants is sold to utilities and the steam costs are allocated to our oil and natural gas operations. All of our electricity sales contracts in place with the utilities are currently scheduled to terminate in 2009, and while we intend to enter into future contracts with the utilities, all of the terms of such contracts are currently the subject of contested proceedings before the California Public Utilities Commission ("CPUC"). Additionally, legal and regulatory decisions (especially related to the pricing of electricity under the contracts such as the SRAC Decision (as defined in our Annual Report on Form 10-K for the year ended December 31, 2008) and the pending issues as to effective dates on retroactivity), can by reducing our electricity revenues adversely affect the economics of our cogeneration facilities and as a result the cost of steam for use in our oil and natural gas operations. In addition, any final determination by the CPUC to apply the new SRAC pricing formula retroactively, if applied so as to require payment on a one-time basis, could have a material adverse effect on our financial condition and results of operations.

***A shortage of natural gas in California could adversely affect our business.***

We may be subject to the risks associated with a shortage of natural gas and/or the transportation of natural gas into and within California. We are highly dependent on sufficient volumes of natural gas necessary to use for fuel in generating steam in our heavy oil operations in California. If the required volume of natural gas for use in our operations were to be unavailable or too highly priced to produce heavy oil economically, our production could be adversely impacted. We have firm transportation to move 12,000 MMBtu/D on the Kern River Pipeline from the Rocky Mountains to Kern County, CA, which accounts for approximately one-third of our current requirement.

***Our use of oil and natural gas price and interest rate hedging contracts involves credit risk and may limit future revenues from price increases or reduced expenses from lower interest rates, as well as result in significant fluctuations in net income and shareholders' equity.***

We use hedging transactions with respect to a portion of our oil and natural gas production with the objective of achieving a more predictable cash flow, and reducing our exposure to a significant decline in the price of crude oil and natural gas. We also utilize interest rate hedges to fix the rate on a portion of our variable rate indebtedness, as only a portion of our total indebtedness has a fixed rate and we are therefore exposed to fluctuations in interest rates. While the use of hedging transactions limits the downside risk of price declines or rising interest rates, as applicable, their use may also limit future revenues from price increases or reduced expenses from lower interest rates, as applicable. Hedging transactions also involve the risk that the counterparty may be unable to satisfy its obligations.

***Our future success depends on our ability to find, develop and acquire oil and natural gas reserves.***

To maintain production levels, we must locate and develop or acquire new oil and natural gas reserves to replace those depleted by production. Without successful exploration, exploitation or acquisition activities, our reserves, production and revenues will decline. We may not be able to find, develop or acquire additional reserves at an acceptable cost. In addition, substantial capital is required to replace and grow reserves. If lower oil and natural gas prices or operating difficulties result in our cash flow from operations being less than expected or limit our ability to borrow under credit arrangements, we may be unable to expend the capital necessary to locate and to develop or acquire new oil and natural gas reserves.

***Actual quantities of recoverable oil and natural gas reserves and future cash flows from those reserves, future production, oil and natural gas prices, revenues, taxes, development expenditures and operating expenses most likely will vary from estimates.***

It is not possible to measure underground accumulations of oil or natural gas in an exact way. Estimating accumulations of oil and natural gas is a complex process that relies on subjective interpretations of available geologic, geophysical, engineering and production data. The extent, quality and reliability of this data can vary. The process also requires certain economic assumptions, such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds, some of which are mandated by the SEC. The accuracy of a reserve estimate is a function of:

- quality and quantity of available data;
- interpretation of that data; and
- accuracy of various mandated economic assumptions.

Any significant variance could materially affect the quantities and present value of our reserves. For example, our ultimate recovery of oil in place on our California diatomite assets could be significantly less than our current target of 23%, and there can be no assurance that our expectations with regard to resource additions from the Piceance Basin will prove to be accurate. In addition, we may adjust estimates of proved reserves to reflect production history, results of development and exploration and prevailing oil and natural gas prices.

In accordance with SEC requirements, we base the estimated discounted future net cash flows from proved reserves on prices and costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of the estimate.

***Future commodity price declines and/or increased capital costs may result in a write-down of our asset carrying values which could adversely affect our results of operations and limit our ability to borrow funds.***

Declines in oil and natural gas prices may result in our having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of development costs increase, production data factors change or drilling results deteriorate, accounting rules may require us to write down, as a non-cash charge to earnings, the carrying value of our oil and natural gas properties for impairments.

We capitalize costs to acquire, find and develop our oil and natural gas properties under the successful efforts accounting method. If net capitalized costs of our oil and natural gas properties exceed fair value, we must charge the amount of the excess to earnings. We review the carrying value of our properties annually and at any time when events or circumstances indicate a review is necessary, based on estimated prices as of the end of the reporting period. The carrying value of oil and natural gas properties is computed on a field-by-field basis. Once incurred, a writedown of oil and natural gas properties is not reversible at a later date even if oil or natural gas prices increase. While we did not incur any such impairment charges in 2008 or the first quarter of 2009, it is possible that declining commodity prices could prompt an impairment in the future. We may incur impairment charges in the future, which could

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have a material adverse effect on our results of operations in the period incurred and on our ability to borrow funds under our senior secured revolving credit facility.

***Competitive industry conditions may negatively affect our ability to conduct operations.***

Competition in the oil and gas industry is intense, particularly with respect to the acquisition of producing properties and of proved undeveloped acreage. Major and independent oil and natural gas companies actively bid for desirable oil and natural gas properties, as well as for the equipment, supplies, labor and services required to operate and develop their properties. Some of these undeveloped reserves may be limited and have higher prices due to current strong demand. Many of our competitors have financial resources that are substantially greater than ours, which may adversely affect our ability to compete within the industry.

Many of our larger competitors not only drill for and produce oil and natural gas but also carry on refining operations and market petroleum and other products on a regional, national or worldwide basis. These companies may be able to pay more for oil and natural gas properties and evaluate, bid for and purchase a greater number of properties than our financial or human resources permit. In addition, there is substantial competition for investment capital in the oil and natural gas industry. These larger companies may have a greater ability to continue drilling activities during periods of low oil and natural gas prices and to absorb the burden of present and future federal, state, local and other laws and regulations. Our inability to compete effectively with larger companies could have a material adverse impact on our business activities, financial condition and results of operations.

***Drilling is a high-risk activity.***

Our future success will partly depend on the success of our drilling program. In addition to the numerous operating risks described in more detail below, these drilling activities involve the risk that no commercially productive oil or natural gas reservoirs will be discovered. Also, we are often uncertain as to the future cost or timing of drilling, completing and producing wells. Furthermore, drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including:

- obtaining government and tribal required permits;
- unexpected drilling conditions;
- pressure or irregularities in formations;
- equipment failures or accidents;
- adverse weather conditions;
- compliance with governmental or landowner requirements; and
- shortages or delays in the availability of drilling rigs and the delivery of equipment and/or services, including experienced labor.

As a result, there can be no assurance that our anticipated production levels will be realized. For example, although we expect that our diatomite production will increase over 50% during 2009, averaging approximately 3,000 Bbl/D, actual production from these assets could be significantly lower.

***The oil and natural gas business involves many operating risks that can cause substantial losses; insurance will not protect us against all of these risks.***

These risks include:

- fires;
- explosions;

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- blow-outs;
- uncontrollable flows of oil, natural gas, formation water or drilling fluids;
- natural disasters;
- pipe or cement failures;
- casing collapses;
- embedded oilfield drilling and service tools;
- abnormally pressured formations;
- major equipment failures, including cogeneration facilities; and
- environmental hazards such as oil spills, natural gas leaks, pipeline ruptures and discharges of toxic gases.

If any of these events occur, we could incur substantial losses as a result of:

- injury or loss of life;
- severe damage or destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- investigatory and clean-up responsibilities;
- regulatory investigation and penalties;
- suspension of operations; and
- repairs to resume operations.

If we experience any of these problems, our ability to conduct operations could be adversely affected. If a significant accident or other event occurs and is not fully covered by insurance, it could adversely affect us. In accordance with customary industry practices, we maintain insurance coverage against some, but not all, potential losses in order to protect against the risks we face. For instance, we do not carry business interruption insurance. We may elect not to carry insurance if our management believes that the cost of available insurance is excessive relative to the risks presented. In addition, we cannot insure fully against pollution and environmental risks. The occurrence of an event not fully covered by insurance could have a material adverse effect on our financial condition and results of operations. While we intend to obtain and maintain insurance coverage we deem appropriate for these risks, there can be no assurance that our operations will not expose us to liabilities exceeding such insurance coverage or to liabilities not covered by insurance.

***We are subject to complex federal, state, regional, local and other laws and regulations that could give rise to substantial liabilities from environmental contamination or otherwise adversely affect our cost, manner or feasibility of doing business.***

All facets of our operations are regulated extensively at the federal, state, regional and local levels. In addition, a portion of our leases in Uinta are, and some of our future leases may be, regulated by Native American tribes. Environmental laws and regulations impose limitations on our discharge of pollutants into the environment, establish standards for our management, treatment, storage, transportation and disposal of hazardous materials and of solid and hazardous wastes, and impose on us obligations to investigate and remediate contamination in certain circumstances. We also must satisfy, in some cases, federal and state requirements for providing environmental assessments, environmental impact studies and/or plans of development before we commence exploration and production activities. Environmental and other requirements applicable to our operations generally have become more stringent in recent years,

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and compliance with those requirements more expensive. Frequently changing environmental and other governmental laws and regulations have increased our costs to plan, design, drill, install, operate and abandon oil and natural gas wells and other facilities, and may impose substantial liabilities if we fail to comply with such regulations or for any contamination resulting from our operations. Our business results from operations and financial condition may be adversely affected by any failure to comply with, or future changes to, these laws and regulations. In particular, failure to comply with these laws and regulations may result in the suspension or termination of our operations and subject us to administrative, civil and criminal penalties. We are currently involved in negotiations with the U.S. Environmental Protection Agency or "EPA" relating to alleged late filing under the federal Clean Air Act of certain leak detection and repair reports for one of our facilities in Utah, pursuant to which the EPA has proposed a penalty in excess of $100,000. In an unrelated matter, we are also involved in negotiations with the Colorado Department of Health and Environment relating to an alleged failure under state law to implement certain best management practices designed to limit impacts to stormwater discharges at certain of our construction sites in Colorado, for which the agency has proposed a penalty in excess of $100,000.

From time to time we have experienced accidental spills, leaks and other discharges of contaminants at some of our properties. We could be liable for the investigation or remediation of such contamination, as well as other liabilities concerning hazardous materials or contamination such as claims for personal injury or property damage. We have incurred expenses and penalties in connection with remediation of contamination in the past, and we may do so in the future. Such liabilities may arise at many locations, including properties in which we have an ownership interest but no operational control, properties we formerly owned or operated and sites where our wastes have been treated or disposed of, as well as at properties that we currently own or operate, and may arise even where the contamination does not result from any noncompliance with applicable environmental laws. Under a number of environmental laws, including the Comprehensive Environmental Response, Compensation and Liability Act ("CERCLA"), such liabilities may be joint and several, meaning that we could be held responsible for more than our share of the liability involved, or even the entire share. Some of the properties that we have acquired, or in which we may hold an interest but not operational control, may have past or ongoing contamination for which we may be held responsible. Some of our operations are in environmentally sensitive areas that may provide habitat for endangered or threatened species, and other protected areas, and our operations in such areas must satisfy additional regulatory requirements. Moreover, public interest in environmental protection has increased in recent years, and environmental organizations have opposed certain drilling projects and/or access to prospective lands and have filed litigation to attempt to stop such projects, including decisions by the Bureau of Land Management regarding several leases in Utah that we have been awarded.

Our activities are also subject to regulation by oil and natural gas-producing states and one Native American tribe of conservation practices and protection of correlative rights. These regulations affect our operations and limit the quantity of oil and natural gas we may produce and sell. A major risk inherent in our drilling plans is the need to obtain drilling permits from federal, state, local and Native American tribal authorities. Delays in obtaining regulatory approvals or drilling permits, the failure to obtain a drilling permit for a well, or the receipt of a permit with unreasonable conditions that are more expensive than we have anticipated could have a negative effect on our ability to explore or develop our properties. Additionally, the oil and natural gas regulatory environment could change in ways that might substantially increase the financial and managerial costs to comply with the requirements of these laws and regulations and, consequently, adversely affect our profitability.

Recent and future environmental regulations, including additional federal and state restrictions on greenhouse gas emissions that may be passed in response to climate change concerns, may increase our operating costs and also reduce the demand for the oil and natural gas we produce. The oil and gas industry is a direct source of certain greenhouse gas (GHG) emissions, such as carbon dioxide and

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methane, and future restrictions on such emissions could impact our future operations. Specifically, on April 17. 2009, EPA issued a notice of its finding and determination that emission of carbon dioxide, methane, and other GHGs present an endangerment to human health and the environment because emissions of such gases are, according to EPA, contributing to warming of the earth's atmosphere. EPA's finding and determination allows it to begin regulating emissions of GHGs under existing provisions of the federal Clean Air Act. Although it may take EPA several years to adopt and impose regulations limiting emissions of GHGs, any such regulation could require us to incur costs to reduce emissions of GHGs associated with our operations. At the state level, more than one-third of the states, including California, have begun taking actions to control and/or reduce emissions of GHGs. The California Global Warming Solutions Act of 2006, also known as "AB 32," caps California's greenhouse gas emissions at 1990 levels by 2020, and the California Air Resources Board is currently developing mandatory reporting regulations and early action measures to reduce GHG emissions prior to January 1, 2012. Although most of the regulatory initiatives developed or being developed by the various states have to date been focused on large sources of GHG emissions, such as coal-fired electric power plants, it is possible that smaller sources of emissions could become subject to GHG emission limitations in the future. A number of our personnel are involved in monitoring the establishment of these regulations through industry trade groups and other organizations in which we are a member. It is not possible, at this time, to estimate accurately how these regulations would impact our business.

***Property acquisitions are a component of our growth strategy, and our failure to complete future acquisitions successfully could reduce our earnings and slow our growth.***

Our business strategy has emphasized growth through strategic acquisitions, but we may not be able to continue to identify properties for acquisition or we may not be able to make acquisitions on terms that we consider economically acceptable. There is intense competition for acquisition opportunities in our industry. Competition for acquisitions may increase the cost of, or cause us to refrain from, completing acquisitions. Our strategy of completing acquisitions is dependent upon, among other things, our ability to obtain debt and equity financing and, in some cases, regulatory approvals. If we are unable to achieve strategic acquisitions, our growth may be impaired, thus impacting earnings, cash from operations and reserves.

***Acquisitions are subject to the uncertainties of evaluating recoverable reserves and potential liabilities.***

Our recent growth is due in part to acquisitions of properties with additional development potential and properties with minimal production at acquisition but significant growth potential, and we expect acquisitions will continue to contribute to our future growth. Successful acquisitions require an assessment of a number of factors, many of which are beyond our control. These factors include: recoverable reserves, exploration potential, future oil and natural gas prices, operating costs, production taxes and potential environmental and other liabilities. Such assessments are inexact and their accuracy is inherently uncertain. In connection with our assessments, we perform a review of the acquired properties, which we believe is generally consistent with industry practices. However, our reviews of acquired properties are inherently incomplete because it generally is not feasible to perform an in-depth review of the individual properties involved in each acquisition. Even a detailed review of records and properties may not necessarily reveal all existing or potential problems, nor will it permit a buyer to become sufficiently familiar with the properties to assess fully their deficiencies and potential problems, including structural, subsurface and environmental problems that may exist or arise. Inspections may not always be performed on every well, and environmental problems, such as ground water contamination, are not necessarily observable even when an inspection is undertaken. Our review prior to signing a definitive purchase agreement may be even more limited.

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We generally are not entitled to contractual indemnification for preclosing liabilities, including environmental liabilities, on acquisitions. Often, we acquire interests in properties on an "as is" basis with limited remedies for breaches of representations and warranties. If material breaches are discovered by us prior to closing, we could require adjustments to the purchase price or, if the claims are significant, we or the seller may have a right to terminate the agreement. We could also fail to discover breaches or defects prior to closing and incur significant unknown liabilities, including environmental liabilities, or experience losses due to title defects, for which we would have limited or no contractual remedies or insurance coverage.

***There are risks in acquiring producing properties, including difficulties in integrating acquired properties into our business, additional liabilities and expenses associated with acquired properties, diversion of management attention, and costs of increased scope, geographic diversity and complexity of our operations.***

Increasing our reserve base through acquisitions is an important part of our business strategy. Any acquisition involves potential risks, including, among other things:

- the validity of our assumptions about reserves, future production, the future prices of oil and natural gas, revenues and costs, including synergies;
- an inability to integrate successfully the properties and businesses we acquire;
- a decrease in our liquidity to the extent we use a significant portion of our available cash or borrowing capacity to finance acquisitions;
- a significant increase in our interest expense or financial leverage if we incur debt to finance acquisitions;
- the assumption of unknown liabilities, losses or costs for which we are not indemnified or for which our indemnity is inadequate;
- the diversion of management's attention from other business concerns;
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets;
- unforeseen difficulties encountered in operating in new geographic areas; and
- customer or key employee losses at the acquired businesses.

Our decision to acquire a property or business will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations.

***If third-party pipelines interconnected to our natural gas wells and gathering facilities become partially or fully unavailable to transport our natural gas, our results of operations and financial condition could be adversely affected.***

We depend upon third party pipelines that provide delivery options from our wells and gathering facilities. Since we do not own or operate these pipelines, their continuing operation in their current manner is not within our control. If any of these third-party pipelines become partially or fully unavailable to transport our natural gas, or if the natural gas quality specifications for their pipelines change so as to restrict our ability to deliver natural gas to those pipelines, our revenues and cash available for distribution could be adversely affected.

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***A change in the jurisdictional characterization of some of our assets by federal, state or local regulatory agencies or a change in policy by those agencies may result in increased regulation of our assets, which may cause our revenues to decline and operating expenses to increase.***

Section 1(b) of the Natural Gas Act ("NGA") exempts natural gas gathering facilities from regulation by the Federal Energy Regulatory Commission ("FERC") as a natural gas company under the NGA. We believe that the natural gas pipelines in our gathering systems meet the traditional tests FERC has used to establish a pipeline's status as a gatherer not subject to regulation as a natural gas company, but the status of these lines has never been challenged before FERC. The distinction between FERC-regulated transmission services and federally unregulated gathering services is subject to change based on future determinations by FERC, the courts, or Congress, and application of existing FERC policies to individual factual circumstances. Accordingly the classification and regulation of some of our natural gas gathering facilities may be subject to challenge before FERC or subject to change based on future determinations by FERC, the courts, or Congress. In the event our gathering facilities are reclassified to FERC-regulated transmission services, we may be required to charge lower rates and our revenues could thereby be reduced.

***Should we fail to comply with all applicable FERC-administered statutes, rules, regulations and orders, we could be subject to substantial penalties and fines.***

FERC has recently issued an order requiring certain participants in the natural gas market, including natural gas gatherers and marketers, that engage in a minimum level of natural gas sales or purchases to submit annual reports regarding those transactions to FERC. In addition, FERC has issued an order requiring major non-interstate pipelines, defined as certain non-interstate pipelines delivering, on an annual basis, more than an average of 50 million MMBtu of gas over the previous three calendar years, to post daily certain information regarding the pipeline's capacity and scheduled flows for each receipt and delivery point that has design capacity equal to or greater than 15,000 MMBtu per day. Should we fail to comply with these requirements or any other applicable FERC-administered statute, rule, regulation or order, we could be subject to substantial penalties and fines. Under the Energy Policy Act of 2005, or EP Act 2005, FERC has civil penalty authority under the NGA to impose penalties for current violations of up to $1 million per day for each violation and disgorgement of profits associated with any violation.

***The loss of key personnel could adversely affect our business.***

We depend to a large extent on the efforts and continued employment of our executive management team and other key personnel. The loss of the services of these or other key personnel could adversely affect our business, and we do not maintain key man insurance on the lives of any of these persons. Our drilling success and the success of other activities integral to our operations will depend, in part, on our ability to attract and retain experienced geologists, engineers, landmen and other professionals. Competition for many of these professionals is intense. If we cannot retain our technical personnel or attract additional experienced technical personnel and professionals, our ability to compete could be harmed.

***We may not adhere to our proposed drilling schedule.***

Our final determination of whether to drill any scheduled or budgeted wells will depend on a number of factors, including:

- results of our exploration efforts and the acquisition, review and analysis of our seismic data, if any;
- availability of sufficient capital resources to us and any other participants for the drilling of the prospects;

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- approval of the prospects by other participants after additional data has been compiled;
- economic and industry conditions at the time of drilling, including prevailing and anticipated prices for oil and natural gas and the availability and prices of drilling rigs and crews; and
- availability of leases, license options, farm-outs, other rights to explore and permits on reasonable terms for the prospects.

Although we have identified or budgeted for numerous drilling prospects, we may not be able to lease or drill those prospects within our expected time frame, or at all. For instance, our drilling schedule may vary from our expectations because of future uncertainties and rig availability and access to our drilling locations utilizing available roads. In addition, we will not necessarily drill wells on all of our identified drilling locations on our acreage.

***We may incur losses as a result of title deficiencies.***

We acquire from third parties, or directly from the mineral fee owners, working and revenue interests in the oil and natural gas leaseholds and estates upon which we will perform our exploration activities. The existence of a material title deficiency can reduce the value or render a property worthless thus adversely affecting the results of our operations and financial condition. Title insurance covering mineral leaseholds is not always available and when available is not always obtained. As is customary in our industry, we rely upon the judgment of staff and independent landmen who perform the field work of examining records in the appropriate governmental offices and abstract facilities before attempting to acquire or place under lease a specific mineral interest and/or undertake drilling activities. We, in some cases, perform curative work to correct deficiencies in the marketability of the title to us. In cases involving title problems, the amount paid for affected oil and natural gas leases or estates can be generally lost, and a prospect can become undrillable.

***Risks Related to our Indebtedness and the Notes***

***We have a substantial amount of debt and the cost of servicing that debt could adversely affect our business and hinder our ability to make payments on the notes, and such risk could increase if we incur more debt.***

We have a substantial amount of indebtedness. At April 27, 2009, we had total long-term outstanding debt of $1.1 billion and no short-term debt. On October 17, 2008, we amended our senior secured revolving credit facility to increase our borrowing base from $1.0 billion to $1.25 billion with current commitments of $1.21 billion and a new maturity date of July 15, 2012. Our borrowing base was subsequently reduced to $1.05 billion upon a scheduled redetermination on April 27, 2009. Also on April 27, 2009 we entered into a $140 million second lien term loan, which matures on January 16, 2013. Although proceeds from the second lien term loan were used to repay a portion of our borrowings under our senior secured revolving credit facility, each dollar outstanding under the second lien term loan reduces the borrowing base under our senior secured revolving credit facility by 30 cents. Also, the issuance of the notes will automatically reduce the borrowing base under our senior secured revolving credit facility by 25 cents per dollar of notes issued. After giving effect to this offering, the application of net proceeds therefrom and the decrease in our borrowing base, at April 27, 2009 we would have had a borrowing base of $933 million and approximately $            million outstanding under our senior secured revolving credit facility, with additional borrowing availability of $            million under that facility.

We have demands on our cash resources in addition to interest expense on the notes, including, among others, operating expenses and interest and principal payments under our senior secured revolving credit facility, our senior secured money market line of credit and our $8^1/_4$% senior subordinated notes. Our level of indebtedness relative to our proved reserves and these significant demands on our cash

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resources could have important effects on our business and on your investment in the notes. For example, they could:

- make it more difficult for us to satisfy our obligations with respect to the notes and our other debt;
- require us to dedicate a substantial portion of our cash flow from operations to payments on our debt, thereby reducing the amount of our cash flow available for working capital, capital expenditures, acquisitions and other general corporate purposes;
- require us to make principal payments under our senior secured revolving credit facility if the quantity of proved reserves attributable to our natural gas and crude oil properties are insufficient to support our level of borrowings under that credit facility;
- limit our flexibility in planning for, or reacting to, changes in the oil and gas industry;
- place us at a competitive disadvantage compared to our competitors that have lower debt service obligations and significantly greater operating and financing flexibility than we do;
- limit our financial flexibility, including our ability to borrow additional funds, pay dividends, make certain investments and issue equity on favorable terms or at all;
- increase our interest expense if interest rates increase, because borrowings under our senior secured revolving credit facility are at a variable rate of interest, and borrowings under our senior secured money market line of credit are generally at a variable rate of interest;
- increase our vulnerability to general adverse economic and industry conditions; and
- result in an event of default upon a failure to comply with financial covenants contained in our senior secured revolving credit facility or senior secured money market line of credit which, if not cured or waived, could have a material adverse effect on our business, financial condition or results of operations.

A higher level of indebtedness increases the risk that we may default on our obligations. Our ability to pay the principal and interest on our long-term debt, including the notes, and to satisfy our other liabilities will depend upon our future performance and our ability to refinance our debt as it becomes due. Our future operating performance and ability to refinance will be affected by economic and capital markets conditions, oil and natural gas prices, our financial condition, results of operations and prospects and other factors, many of which are beyond our control.

If we are unable to service our indebtedness and fund our operating costs, we will be forced to adopt alternative strategies that may include:

- reducing or delaying capital expenditures;
- seeking additional debt financing or equity capital;

- selling assets; or

- restructuring or refinancing debt.

There can be no assurance that any such strategies could be implemented on satisfactory terms, if at all.

***The borrowing base under our senior secured revolving credit facility may be reduced below the amount of our outstanding borrowings under that facility.***

The amount we are able to borrow under our senior secured revolving credit facility is determined based on the value of our proved oil and natural gas reserves and is based on oil and natural gas price assumptions which vary by individual lender. Our borrowing base is subject to redetermination twice each year in April and October with the option for one additional redetermination each year and additional redeterminations contemporaneously with any issuance of permitted second lien debt and after any issuance of permitted unsecured debt, including the issuance of the notes. Also, each dollar outstanding under our second lien term loan reduces the borrowing base under our senior secured revolving credit facility by 30 cents and each dollar of permitted senior unsecured debt, including the notes, automatically reduces the borrowing base under our senior secured revolving credit facility by 25 cents. Should there be a deficiency in the amount of our borrowing base in comparison to our outstanding debt under the senior secured revolving credit facility, we would be required to repay any such deficiency in two equal installments, 90 and 180 days after the redetermination. If we were unable to make those repayments, we would be in default under our senior secured revolving credit facility, which could have a material adverse effect on our business and financial condition. See "Description of Other Indebtedness."

***Despite current indebtedness levels, we may still be able to incur substantially more debt. This could further exacerbate the risks described above.***

The terms of the indenture governing the notes will permit us to incur substantial additional indebtedness, including significant additional secured debt, under our senior secured revolving credit facility or other facilities. Any secured debt we incur will effectively rank senior to the notes to the extent of the value of the collateral securing that debt. If we incur any additional indebtedness that ranks equally with the notes, the holders of that debt will be entitled to share ratably with you in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of our business. This may have the effect of reducing the amount of proceeds paid to you. If new debt is added to our current debt levels, the related risks that we now face could intensify. See "Description of Notes" and "Description of Other Indebtedness."

***Covenants in agreements governing our debt restrict our ability to engage in certain activities.***

Agreements governing our outstanding debt restrict and the indenture governing the notes will restrict our ability to, among other things:

- incur, assume or guarantee additional indebtedness or issue redeemable stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase debt that is junior in right of payment to the notes;
- make loans and other types of investments;
- incur liens;
- restrict dividends, loans or asset transfers from our subsidiaries;
- sell or otherwise dispose of assets, including capital stock of subsidiaries;
- consolidate or merge with or into, or sell substantially all of our assets to, another person;
- make capital expenditures or acquire assets or businesses;
- enter into transactions with affiliates; and
- enter into new lines of business.

In addition, our senior secured revolving credit facility contains certain covenants, which, among other things, require the maintenance of a minimum current ratio and a minimum earnings (before interest, taxes, depreciation, depletion and amortization, non-cash income and expense) to debt ratio. Our ability to borrow under our senior secured revolving credit facility is dependent upon the quantity of proved reserves attributable to our natural gas and crude oil properties and the respective projected

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commodity prices as determined by the lenders under that credit facility. Our ability to meet these covenants or requirements may be affected by events beyond our control, and we cannot assure you that we will satisfy such covenants and requirements.

***If we default on our obligations to pay our indebtedness we may not be able to make payments on the notes.***

Any default under the agreements governing our indebtedness, including a default under our senior secured revolving c