Midstates Petroleum Company, Inc.
Form 424B3
October 16, 2015

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Filed Pursuant to Rule 424(b)(3)
Registration Statement No. 333-207262

PROSPECTUS

Midstates Petroleum Company, Inc.

Midstates Petroleum Company LLC

Offer to exchange up to

$524,121,000 aggregate principal amount of 12% Senior Secured Third Lien Notes due 2020 that have been registered under the Securities Act of 1933

for

$524,121,000 aggregate principal amount of 12% Senior Secured Third Lien Notes due 2020 that have not been registered under the Securities Act of 1933

The exchange offer and withdrawal rights will expire at 5:00 p.m., New York City time, on November 16, 2015 unless extended.

We are offering to exchange up to $524,121,000 aggregate principal amount of our new 12% Senior Secured Third Lien Notes due 2020, which have been registered under the Securities Act of 1933, as amended (the "Securities Act"), referred to in this prospectus as the "new notes," for any and all of our outstanding unregistered 12% Senior Secured Third Lien Notes due 2020, referred to in this prospectus as the "old notes." We issued the old notes on May 21, 2015 and June 2, 2015 in transactions not requiring registration under the Securities Act. We are offering you new notes in exchange for old notes in order to satisfy our obligations from that previous transaction. The new notes will represent the same debt as the old notes and we will issue the new notes under the same indenture as the old notes. The new notes offered hereby, together with any old notes that remain outstanding after the completion of the exchange offer, will be treated as a single class under the indenture governing them. The old notes and the new notes are collectively referred to in this prospectus as the "notes."

Please read "*Risk Factors*" beginning on page 10 of this prospectus for a discussion of factors you should consider before participating in the exchange offer.

We will exchange the new notes for all outstanding old notes that are validly tendered and not withdrawn before the expiration of the exchange offer. You may withdraw tenders of old notes at any time prior to the expiration of the exchange offer. The exchange procedure is more fully described in "Exchange Offer Procedures for Tendering." If you fail to tender your old notes, you will continue to hold unregistered notes that you will not be able to freely transfer.

The terms of the new notes are substantially identical to the old notes, except that the transfer restrictions, registration rights and provisions for additional interest applicable to the old notes do not apply to the new notes. Please read "Description of New Notes" for more details on the terms of the new notes. We will not receive any cash proceeds from the issuance of the new notes in the exchange offer. The exchange of new notes for old notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes.

Each broker-dealer that receives new notes for its own account pursuant to this offering must acknowledge that it will deliver this prospectus in connection with any resale of such new notes. The letter of transmittal states that by so acknowledging and by delivering a prospectus, a broker-dealer will not be deemed to admit that it is an "underwriter" within the meaning of the Securities Act. This prospectus, as it may be amended or supplemented from time to time, may be used by a broker-dealer in connection with resales of new notes received in exchange for old notes where such old notes were acquired by such broker-dealer as a result of market-making activities or other trading activities. We have agreed that, for a period of up to 180 days after the exchange date (as such period may be extended), we will make this prospectus, as amended or supplemented, available to any broker-dealer for use in connection with any such resale. Please read "Plan of Distribution."

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

The date of this prospectus is October 16, 2015.

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This prospectus is part of a registration statement we filed with the Securities and Exchange Commission, or the "SEC." In making your decision whether to participate in the exchange offer, you should rely only on the information contained in this prospectus and in the letter of transmittal accompanying this prospectus. We have not authorized anyone to provide you with any other information. If you receive any unauthorized information, you must not rely on it. We are not making an offer to sell these securities in any state or jurisdiction where the offer is not permitted. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front cover of this prospectus or the date of such incorporated documents, as the case may be.

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FORWARD-LOOKING STATEMENTS

Various statements contained in this prospectus are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act") and Section 21E of the Exchange Act. These forward-looking statements are subject to a number of risks and uncertainties, many of which are beyond our control. All statements other than statements of historical fact included in this prospectus and any prospectus supplement are forward looking statements, including, without limitation, statements regarding our strategy, future operations, financial position, estimated revenues and losses, projected costs, prospects, plans and objectives of management. When used in this prospectus, the words "could," "believe," "anticipate," "intend," "estimate," "expect," "may," "continue," "predict," "potential," "project" and similar expressions are intended to identify forward-looking statements, although not all forward-looking statements contain such identifying words. In particular, the factors discussed in this prospectus could affect our actual results and cause our actual results to differ materially from expectations, estimates, or assumptions expressed in, forecasted in, or implied in such forward-looking statements.

Forward-looking statements may include statements about our:

- business strategy;
- estimated future net reserves and present value thereof;
- technology;
- financial condition, revenues, cash flows and expenses;
- levels of indebtedness, liquidity and compliance with debt covenants;
- financial strategy, budget, projections and operating results;
- oil and natural gas realized prices;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of oilfield labor;
- availability of third party natural gas gathering and processing capacity;
- the amount, nature and timing of capital expenditures, including future development costs;
- availability and terms of capital;

drilling of wells, including our identified drilling locations;

successful results from our identified drilling locations;

marketing of oil, natural gas liquids and natural gas;

the integration and benefits of asset and property acquisitions or the effects of asset and property acquisitions or dispositions on our cash position and levels of indebtedness;

infrastructure for salt water disposal and electrical power;

sources of electricity utilized in operations and the related infrastructures;

costs of developing our properties and conducting other operations;

general economic conditions;

effectiveness of our risk management activities;

environmental liabilities;

counterparty credit risk;

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- the outcome of pending and future litigation;
- governmental regulation and taxation of the oil and natural gas industry;
- developments in oil-producing and natural gas-producing countries;
- uncertainty regarding our future operating results; and
- plans, objectives, expectations and intentions contained in this prospectus that are not historical.

All forward-looking statements speak only as of the date of this prospectus. You should not place undue reliance on these forward-looking statements. These forward-looking statements are subject to a number of risks, uncertainties and assumptions. Although we believe that our plans, intentions and expectations reflected in or suggested by the forward-looking statements we make in this prospectus are reasonable, we can give no assurance that these plans, intentions or expectations will be achieved or occur, and actual results could differ materially and adversely from those anticipated or implied in the forward-looking statements. We disclose important factors that could cause our actual results to differ materially from our expectations under "Risk Factors".

These factors include:

- variations in the market demand for, and prices of, oil, natural gas liquids and natural gas;
- uncertainties about our estimated quantities of oil, natural gas liquids and natural gas reserves;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our revolving credit facility;
- access to capital and general economic and business conditions;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- risks in connection with acquisitions;
- risks related to the concentration of our operations onshore in Oklahoma, Texas and Louisiana;
- drilling results;
- the potential adoption of new governmental regulations;
- possible exposure to additional tax liabilities; and

our ability to satisfy future cash obligations and environmental costs.

These cautionary statements qualify all forward-looking statements attributable to us or persons acting on our behalf.

Moreover, we operate in a very competitive and rapidly changing environment. New risks emerge from time to time. It is not possible for our management to predict all risks, nor can we assess the impact of all factors on our business or the extent to which any factor, or combination of factors, may cause actual results to differ materially from those contained in any forward-looking statements we may make.

Reserve engineering is a process of estimating underground accumulations of oil, natural gas liquids and natural gas that cannot be measured in an exact way. The accuracy of any reserve estimate depends on the quality of available data, the interpretation of such data and price and cost assumptions made by our reserve engineers. In addition, the results of drilling, testing and production activities may justify revisions of estimates that were made previously. If significant, such revisions would change the schedule of any further production and development drilling. Accordingly, reserve estimates may differ from the quantities of oil, natural gas liquids and natural gas that are ultimately recovered.

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SUMMARY

This summary highlights selected information contained elsewhere in this prospectus. This summary is not complete and does not contain all of the information that you should consider before deciding whether to exchange your old notes for new notes. For a more complete understanding of us and the exchange offer, we encourage you to read this entire document, including "Risk Factors" and the financial and other information included in this prospectus.

Overview

We are an independent exploration and production company focused on the application of modern drilling and completion techniques to oil-focused resources in the United States. Our operations originally focused on the Upper Gulf Coast Tertiary trend onshore in Louisiana, which we refer to as our "Gulf Coast" operating area. We began operations in the Mississippian Lime trend in Oklahoma on October 1, 2012 with our acquisition of interests in producing oil and natural gas assets and unevaluated leasehold acreage in Oklahoma and unevaluated leasehold acreage in Kansas. On May 31, 2013, we acquired producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma. We subsequently acquired additional oil and gas operations and properties in Louisiana, Oklahoma and Texas.

Our principal executive offices are located at 321 South Boston Avenue, Suite 1000, Tulsa, Oklahoma 74103, and our telephone number at that address is (918) 947-8550. Our website address is http://www.midstatespetroleum.com. The information on our website is not part of this prospectus.

As used in this prospectus, "we," "us," "our" and "Midstates" mean Midstates Petroleum Company, Inc. and its only subsidiary, Midstates Petroleum Company LLC, unless we state otherwise or the context otherwise requires, and "Midstates Sub" means Midstates Petroleum Company LLC.

For additional information on our business, properties and financial condition, please refer to the documents cited in "Available Information."

Risk Factors

Investing in the notes involves substantial risks. You should carefully consider all the information contained in this prospectus prior to participating in the exchange offer. In particular, we urge you to consider carefully the factors set forth under "Risk Factors" in this prospectus, together with all of the other information included in this prospectus.

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Exchange Offer

On May 21, 2015 and June 2, 2015, we completed private placements of $504.121 million and $20 million, respectively, in aggregate principal amount of our 12% Senior Secured Third Lien Notes due 2020, or the "old notes." As part of the private placement, we entered into a registration rights agreement with the holders of the old notes in which we agreed, among other things, to deliver this prospectus to you and to use commercially reasonable efforts to cause an exchange offer to be completed within 270 days after the issuance of the old notes. The following is a summary of the exchange offer.

Old Notes	On May 21, 2015 and June 2, 2015, we issued $504.121 million and $20 million, respectively, in aggregate principal amount of 12% Senior Secured Third Lien Notes due 2020.
New Notes	The terms of the new notes are substantially identical to the terms of the old notes, except that the transfer restrictions, registration rights and provisions for additional interest relating to the old notes do not apply to the new notes. The new notes offered hereby, together with any old notes that remain outstanding after the completion of the exchange offer, will be treated as a single class for all purposes under the indenture, including, without limitation, waivers, amendments, redemptions and offers to purchase. The new notes will have a CUSIP number different from that of any old notes that remain outstanding after the completion of the exchange offer.
Exchange Offer	We are offering to exchange up to $524.121 million aggregate principal amount of new notes that have been registered under the Securities Act for an equal amount of the old notes that have not been registered under the Securities Act to satisfy our obligations under the registration rights agreement that we entered into when we issued the old notes in a transaction exempt from registration under the Securities Act.
Expiration Time	The exchange offer will expire at 5:00 p.m., New York City time, on November 16, 2015, unless we decide to extend it.
Conditions to the Exchange Offer	The registration rights agreement does not require us to accept old notes for exchange if the exchange offer or the making of any exchange by a holder of the old notes would violate any applicable law or interpretation of the staff of the SEC or if any legal action has been instituted or threatened that would impair our ability to proceed with the exchange offer. A minimum aggregate principal amount of old notes being tendered is not a condition to the exchange offer. Please read "Exchange Offer Conditions to the Exchange Offer" for more information about the conditions to the exchange offer.

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Procedures for Tendering Old Notes	All of the old notes are held in book-entry form through the facilities of The Depository Trust Company, or "DTC." To participate in the exchange offer, you must follow the automatic tender offer program, or "ATOP," procedures established by DTC for tendering notes held in book-entry form. The ATOP procedures require that the exchange agent receive, prior to the expiration time of the exchange offer, a computer-generated message known as an "agent's message" that is transmitted through ATOP, and that DTC confirm that: DTC has received instruction to exchange your old notes; and you agree to be bound by the terms of the letter of transmittal in Annex A hereto. For more details, please read "Exchange Offer Terms of the Exchange Offer" and "Exchange Offer Procedures for Tendering."
Guaranteed Delivery Procedures	None.
Withdrawal of Tenders	You may withdraw your tender of old notes at any time prior to the expiration time. To withdraw, you must submit a notice of withdrawal to the exchange agent using ATOP procedures before the expiration time of the exchange offer. Please read "Exchange Offer Withdrawal of Tenders."
Acceptance of Old Notes and Delivery of New Notes	If you fulfill all conditions required for proper acceptance of old notes, we will accept any and all old notes that you properly tender and do not validly withdraw before the expiration time of the exchange offer. We will return any old notes that we do not accept for exchange to you without expense promptly after the expiration time of the exchange offer. We will deliver the new notes promptly after the expiration time of the exchange offer. Please read "Exchange Offer Terms of the Exchange Offer."
Fees and Expenses	We will bear all expenses related to the exchange offer. Please read "Exchange Offer Fees and Expenses."
Use of Proceeds	The issuance of the new notes will not provide us with any new proceeds. We are making the exchange offer solely to satisfy our obligations under the registration rights agreement.

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Consequences of Failure to Exchange Old Notes

If you do not exchange your old notes in the exchange offer, you will no longer be able to require us to register the old notes under the Securities Act, except in the limited circumstances provided under the registration rights agreement. In addition, you will not be able to resell, offer to resell or otherwise transfer the old notes unless we have registered the old notes under the Securities Act, or unless you resell, offer to resell or otherwise transfer them under an exemption from the registration requirements of, or in a transaction not subject to, the Securities Act.

U.S. Federal Income Tax and Estate Consequences

The exchange of new notes for old notes in the exchange offer will not be a taxable event for U.S. federal income tax purposes. Please read "Material U.S. Federal Income Tax and Estate Tax Consequences."

Exchange Agent

We have appointed Wilmington Trust, National Association as the exchange agent for the exchange offer. You should direct questions and requests for assistance and requests for additional copies of this prospectus (including the letter of transmittal) to the exchange agent addressed as follows:

By Registered & Certified Mail:
Wilmington Trust, National Association
Rodney Square North
1100 North Market Street
Wilmington, Delaware 19890-1626
Attn: Workflow Management 5th Floor

By regular mail or overnight courier:
Wilmington Trust, National Association
Rodney Square North
1100 North Market Street
Wilmington, Delaware 19890-1626
Attn: Workflow Management 5th Floor

In person by hand only:
Wilmington Trust, National Association
Rodney Square North
1100 North Market Street
Wilmington, Delaware 19890-1626
Attn: Workflow Management 5th Floor

Eligible institutions may make requests by facsimile at (302) 636-4139 and may confirm facsimile delivery by calling (302) 636-6470.

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Terms of the New Notes

The new notes will be substantially identical to the old notes, except that the new notes are registered under the Securities Act and will not have restrictions on transfer, registration rights or provisions for additional interest. The new notes will evidence the same debt as the old notes, and the same indenture will govern the new notes and the old notes. In this prospectus, we sometimes refer to the new notes and the old notes, collectively, as the "notes."

The following summary contains basic information about the new notes and is not intended to be complete. It does not contain all the information that is important to you. For a more complete understanding of the new notes, please read "Description of New Notes."

Issuers	Midstates Petroleum Company, Inc. and Midstates Petroleum Company LLC. Midstates Petroleum Company LLC is a wholly owned sole subsidiary of Midstates Petroleum Company, Inc. through which Midstates Petroleum Company, Inc. conducts its business.
Securities Offered	$524.121 million aggregate principal amount of 12% Senior Secured Third Lien Notes due 2020.
Maturity Date	The earlier of (i) June 1, 2020 and (ii) twelve months after the maturity date of the revolving credit agreement (the "Credit Agreement") and any credit facility that refinances the Credit Agreement.
Interest Payment Dates	Interest is payable on the new notes on June 1 and December 1 of each year commencing December 1, 2015. Interest on each new note will accrue from the date of original issuance of the old note tendered in exchange thereof or, if interest has already been paid, from the date the interest on the old note was most recently paid.
Guarantees	The new notes will be unconditionally guaranteed, jointly and severally, on a senior secured basis (the "new note guarantees") by each of our future restricted subsidiaries (except our unrestricted subsidiaries and certain immaterial subsidiaries) that guarantees or is otherwise obligated with respect to certain indebtedness (the "new note guarantors"). As of the date of this prospectus, Midstates Sub is our only subsidiary.

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Note Collateral	The new notes and the new note guarantees will be initially secured on a third-priority basis by liens, subject in priority only to certain exceptions and permitted liens, on substantially all of our and our new note guarantors' assets that are subject to liens securing our revolving credit facility (the "note collateral"). Pursuant to the terms of the Intercreditor Agreement (as defined below), the liens on the assets securing the new notes and the new note guarantees will be contractually subordinated to liens thereon that secure our revolving credit facility (and future indebtedness incurred to replace or refinance our revolving credit facility) and contractually subordinated to the liens securing our 10% Senior Secured Second Lien Notes due 2020 (the "Second Lien Notes"). Consequently, the new notes and the new note guarantees will be effectively subordinated to the revolving credit facility (and future indebtedness incurred to replace or refinance our revolving credit facility) and contractually subordinated to the liens securing our Second Lien Notes to the extent of the value of the assets securing such indebtedness. Please read "Description of New Notes Security for New Notes."
Intercreditor Agreement	The trustee and the collateral agent appointed under the indenture, the trustee and the collateral agent appointed under the indenture governing our Second Lien Notes and the collateral agent under our revolving credit facility are parties to an intercreditor agreement (the "Intercreditor Agreement") which governs the relationship of holders of the notes, the lenders under our revolving credit facility and holders of any junior lien debt that we may issue in the future, with respect to collateral and certain other matters relating to the administration of security interests, exercise of remedies, certain bankruptcy-related provisions and other intercreditor matters. The Intercreditor Agreement also provides that in the event of a foreclosure on the note collateral or of insolvency proceedings, the holders of the notes will receive proceeds from the note collateral only after obligations under our revolving credit facility (and future indebtedness incurred to replace or refinance our revolving credit facility) and our Second Lien Notes have been paid in full. Certain terms of the Intercreditor Agreement are set forth under "Description of New Notes Intercreditor Agreement."

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Ranking

The new notes and the new note guarantees will be:

effectively junior, pursuant to the terms of the Intercreditor Agreement, to our and the note guarantors' obligations under our revolving credit facility (and future indebtedness incurred to replace or refinance our revolving credit facility), to the extent of the value of the collateral securing such indebtedness, which will be secured on a first priority basis by liens on the same collateral that secure the notes (and any additional notes) and the note guarantees;

effectively junior, pursuant to the terms of the Intercreditor Agreement, to our and the note guarantors' obligations under our Second Lien Notes (and future indebtedness incurred to replace or refinance our Second Lien Notes), to the extent of the value of the collateral securing such indebtedness, which will be secured on a second-priority basis by liens on the same collateral that secure the notes (and any additional notes) and the note guarantees;

effectively senior to all of our existing and future unsecured indebtedness, including our 10.75% senior notes due 2020 (the "2020 Senior Notes") and our 9.25% senior notes due 2021 (the "2021 Senior Notes" and together with the 2020 Senior Notes, the "Senior Unsecured Notes") and the guarantees thereof, to the extent of the value of the collateral securing our secured indebtedness;

effectively senior to all of our future junior lien obligations that rank below a third-priority basis to the extent of the value of the note collateral;

effectively junior to all existing and future secured indebtedness secured by assets not constituting note collateral to the extent of the value of the collateral securing such indebtedness;

equal in right of payment to all of our existing and future senior indebtedness, including our existing Senior Unsecured Notes and our Second Lien Notes;

structurally subordinated to all existing and future indebtedness of any non-guarantor subsidiaries; and

senior in right of payment to all of our future subordinated indebtedness.

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Optional Redemption	At any time prior to June 1, 2017, we may, from time to time, redeem up to 35% of the aggregate principal amount of the notes (including any additional notes) with an amount not greater than the net cash proceeds of certain equity offerings at the redemption price set forth under "Description of New Notes Optional Redemption," if at least 50% of the aggregate principal amount of the notes issued under the indenture remains outstanding immediately after such redemption and the redemption occurs within 180 days after the closing date of such equity offering. At any time prior to June 1, 2017, we may redeem the notes, in whole or in part, at a "make whole" redemption price set forth under "Description of New Notes Optional Redemption." On and after June 1, 2017, we may redeem the notes, in whole or in part, at the redemption prices set forth under "Description of New Notes Optional Redemption."
Change of Control	Upon a change of control (as defined in "Description of New Notes Certain Definitions"), unless we exercise our change of control redemption rights as set forth above, we must offer to repurchase the new notes at 101% of the principal amount, plus accrued and unpaid interest to the purchase date.
Certain Covenants	We will issue the new notes under an indenture, dated May 21, 2015, with Wilmington Trust, National Association, as trustee. The indenture contains certain covenants, including, but not limited to, limitations and restrictions on our ability to: pay dividends or make other distributions on capital stock or subordinated indebtedness; make investments; incur additional indebtedness or issue preferred stock; create certain liens; enter into agreements that restrict dividends or other payments from our restricted subsidiaries to us; consolidate, merge or transfer all or substantially all of our assets; engage in transactions with affiliates; and create unrestricted subsidiaries. These covenants are subject to important exceptions and qualifications. See "Description of New Notes Certain Covenants."

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	Many of the covenants in the indenture will be suspended if the notes are rated investment grade by both Standard & Poor's Rating Services ("S&P") and Moody's Investor Services, Inc. ("Moody's") and no default has occurred and is continuing.
No Public Market	The new notes are a series of securities for which there is currently no established trading market. A liquid market for the new notes may not be available if you try to sell your notes. We do not intend to apply for a listing of the new notes on any securities exchange or any automated dealer quotation system.
Transfer Restrictions	The new notes generally will be freely tradable.
Risk Factors	Please see "Risk Factors" beginning on page 10 herein and the other information in this prospectus for a discussion of factors you should carefully consider before participating in the exchange offer.

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RISK FACTORS

You should carefully consider the risk factors and all of the other information included in this prospectus and the documents we have filed with the SEC, including those in "Risk Factors," in evaluating an investment in the new notes. If any of these risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected.

Risks Relating to the Exchange Offer

If you do not properly tender your old notes, you will continue to hold unregistered outstanding notes and your ability to transfer outstanding notes will be adversely affected.

We will only issue new notes in exchange for old notes that you timely and properly tender. Therefore, you should allow sufficient time to ensure timely delivery of the old notes and you should carefully follow the instructions on how to tender your old notes. Neither we nor the exchange agent is required to tell you of any defects or irregularities with respect to your tender of old notes. Please read "Exchange Offer Procedures for Tendering" and "Description of New Notes."

If you do not exchange your old notes for new notes in the exchange offer, you will continue to be subject to the restrictions on transfer of your old notes described in the legend on the certificates for your old notes. In general, you may only offer or sell the old notes if they are registered under the Securities Act and applicable state securities laws, or offer and sell under an exemption from these requirements. We do not plan to register any sale of the old notes under the Securities Act. For further information regarding the consequences of failing to exchange your old notes in the exchange offer, please read "Exchange Offer Consequences of Failure to Exchange."

You may find it difficult to sell your new notes.

The new notes are a new issue of securities and, although the new notes will be registered under the Securities Act, the new notes will not be listed on any securities exchange. Because there is no public market for the new notes, you may not be able to resell them.

We cannot assure you that an active market will develop for the new notes or that any trading market that does develop will be liquid. If an active market does not develop or is not maintained, the market price and liquidity of the new notes may be adversely affected. If a market for the new notes develops, they may trade at a discount from their initial offering price. The trading market for the new notes may be adversely affected by:

- changes in the overall market for non-investment grade securities;
- changes in our financial performance or prospects;
- the financial performance or prospects for companies in our industry generally;
- the number of holders of the new notes;
- the interest of securities dealers in making a market for the new notes; and
- prevailing interest rates and general economic conditions.

Historically, the market for non-investment grade debt has been subject to substantial volatility in prices. The market for the new notes, if any, may be subject to similar volatility. Prospective investors in the new notes should be aware that they may be required to bear the financial risks of such investment for an indefinite period of time.

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Some holders who exchange their old notes may be deemed to be underwriters.

If you exchange your old notes in the exchange offer for the purpose of participating in a distribution of the new notes, you may be deemed to have received restricted securities and, if so, will be required to comply with the registration and prospectus delivery requirements of the Securities Act in connection with any resale transaction.

Risks Relating to the Notes

We may not be able to generate sufficient cash flows to service all of our indebtedness, including the notes, our Second Lien Notes and our Senior Unsecured Notes, and may be forced to take other actions in order to satisfy our obligations under our indebtedness, which may not be successful. If we are unable to repay or refinance our existing and future debt as it becomes due, we may be unable to continue as a going concern.

Our ability to make scheduled payments on, or to refinance, our debt obligations, including the notes, our Second Lien Notes and our Senior Unsecured Notes, will depend on our financial and operating performance, which is subject to prevailing economic and competitive conditions and certain financial, business and other factors beyond our control. Our existing and future debt agreements could create issues as interest payments become due and the debt matures that will threaten our ability to continue as a going concern. We cannot assure you that our business will generate sufficient cash flows from operating activities or that future sources of capital will be available to us in an amount sufficient to permit us to service our indebtedness, including the notes, our Second Lien Notes and our Senior Unsecured Notes, or to fund our other liquidity needs. Our credit facility and the indentures governing the notes, our Second Lien Notes and the Senior Unsecured Notes restrict our ability to dispose of assets and our use of any of the proceeds. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms, would materially and adversely affect our financial condition and results of operations and our ability to satisfy our obligations under the notes.

We have substantial interest payments due during the remainder of 2015. If we cannot make scheduled payments on our debt, we will be in default and, as a result:

- our debt holders could declare all outstanding principal and interest to be due and payable;
- the lenders under our revolving credit facility could terminate their commitments to lend us money and foreclose against the assets securing their borrowings; and
- we could be forced into bankruptcy or liquidation.

All of these events could result in you losing your investment in the notes. While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or otherwise extend the maturity dates, and to cure any potential defaults, there is no assurance that any particular actions with respect to refinancing existing indebtedness, extending the maturity of existing indebtedness or curing potential defaults in our existing and future debt agreements will be sufficient.

Despite our current level of indebtedness, we may incur substantially more debt in the future, which could further exacerbate the risks described above. Furthermore, we are permitted to incur additional debt, under the terms of the credit agreements governing our credit facility, subject to borrowing base availability, and the indentures governing the notes, our Second Lien Notes and our Senior Unsecured Notes, subject to certain limitations, which in each case could intensify the related risks that we and our subsidiary now face. See "Description of New Notes."

The consolidated financial statements included in this prospectus have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial

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statements do not reflect any adjustments that might result if we are unable to continue as a going concern.

We may be able to incur substantially more debt. This could exacerbate the risks associated with our indebtedness.

Our total consolidated indebtedness consists of $524.121 million in aggregate principal amount of the notes, $625 million in aggregate principal amount of our Second Lien Notes, $293.6 million in aggregate principal amount of our 2020 Senior Notes and $347.7 million in aggregate principal amount of our 2021 Senior Notes. The covenants contained in the agreements governing our outstanding indebtedness, including the indenture for the notes, our Second Lien Notes, our 2020 Senior Notes and 2021 Senior Notes, limit, among other things, our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments. Any borrowings under the revolving credit facility will be secured on a first lien basis, and, as a result, will be effectively senior to the notes and the guarantees of the notes by any guarantors, to the extent of the value of the collateral securing that indebtedness.

In addition, the holders of any future secured debt we may incur that ranks equally with the notes may be entitled to share with the holders of the notes in any proceeds distributed in connection with any insolvency, liquidation, reorganization, dissolution or other winding-up of us. This may have the effect of reducing the amount of proceeds paid to you in such an event. If new debt is added to our current debt levels, the related risks that we now face could intensify.

Our substantial indebtedness, liquidity issues and potential to seek restructuring transactions may have a material adverse effect on our business and operations.

Our substantial indebtedness, liquidity issues and potential to seek restructuring transactions may result in uncertainty about our business and cause, among other things:

- third parties' to lose confidence in our ability to explore and produce oil and natural gas, resulting in a significant decline in our revenues, profitability and cash flow;

- difficulty retaining, attracting or replacing key employees;

- employees to be distracted from performance of their duties or more easily attracted to other career opportunities; and

- our suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

These events may have a material adverse effect on our business and operations.

Our variable rate indebtedness subjects us to interest rate risk, which could cause our debt service obligations to increase significantly.

We are subject to interest rate risk in connection with borrowings under our credit facility, which bears interest at variable rates. Interest rate changes will not affect the market value of any debt incurred under such facility, but could affect the amount of our interest payments, and accordingly, our future earnings and cash flows, assuming other factors are held constant. We currently do not have any interest rate hedging arrangements with respect to the credit facility. In the future, we may enter into interest rate swaps that involve the exchange of floating for fixed rate interest payments in order to reduce interest rate volatility; however, any swaps we enter into may not fully mitigate our interest rate risk. A significant increase in prevailing interest rates, which results in a substantial increase in the interest rates applicable to our interest expense could have a material adverse effect on our financial condition and results of operations.

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Our revolving credit facility and the indentures governing the notes, our Second Lien Notes and our Senior Unsecured Notes contain certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our revolving credit facility and the indentures governing the notes, our Second Lien Notes and our Senior Unsecured Notes include certain covenants that, among other things, restrict:

- our ability to incur or assume additional debt or provide guarantees in respect of obligations of other persons;
- issue redeemable stock and preferred stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- create or incur liens;
- restrict distributions from our subsidiaries;
- sell assets and capital stock of our subsidiaries;
- consolidate or merge with or into another entity, or sell all or substantially all of our assets; and
- enter into new lines of business.

A breach of the covenants under the indenture governing the notes, the revolving credit facility or the indentures governing the notes, our Second Lien Notes and our Senior Unsecured Notes could result in an event of default under the applicable indebtedness. An event of default may allow the creditors to accelerate the related debt and may result in an acceleration of any other debt to which a cross-acceleration or cross-default provision applies. In addition, an event of default under our credit facility would permit the lenders under the facility to terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders under our revolving credit facility could proceed against the collateral granted to them to secure that debt.

In addition, our revolving credit facility requires us to maintain certain financial ratios, including a leverage ratio. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our revolving credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our revolving credit facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our revolving credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our revolving credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

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Our level of indebtedness may increase and reduce our financial flexibility.

In the future, we may incur significant additional indebtedness in order to make future acquisitions or to develop our properties. Our current level of indebtedness could affect our operations in several ways, including the following:

- causing a significant portion of our cash flows to be used to service our indebtedness, thereby reducing the availability of cash flows for working capital, capital expenditures and other general business activities;
- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, such competitors may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- causing our debt covenants to affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- making it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then outstanding bank borrowings;
- impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- making it more difficult for us to satisfy our obligations under the indentures governing our Senior Unsecured Notes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control.

If we are unable to repay our debt out of our cash on hand, we could attempt to refinance such debt, obtain additional borrowings, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that refinancing, additional borrowings, proceeds from the sale of assets or equity financing will be available to pay or refinance such debt. Factors that may affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions, our market value, our reserve levels and our operating performance at the time of such offering or other financing. The inability to repay or refinance our debt could have a material adverse effect on our operations and could result in a reduction in our capital program or lead us to pursue other alternatives to develop our assets.

In addition, our bank borrowing base is subject to periodic redeterminations on a semi-annual basis, effective October 1 and April 1 and up to one additional time per six-month period following each scheduled borrowing base redetermination, as may be requested by either us or the administrative agent under our revolving credit facility. In the future we could be forced to repay a portion of our then outstanding bank borrowings due to future redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are unable to arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

We may be unable to maintain compliance with certain financial ratio covenants of our outstanding indebtedness which could result in an event of default that, if not cured or waived, would have a material adverse effect on our business, financial condition and results of operations.

We are in compliance with our financial covenants; however, we cannot guarantee that we will be able to comply with such terms at all times in the future. Any failure to comply with the conditions and covenants in our revolving credit facility that is not waived by our lenders or otherwise cured could lead to a termination of our revolving credit facility, acceleration of all amounts due under our revolving credit facility, or trigger cross-default provisions under other financing arrangements. These restrictions may limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our indebtedness impose on us.

The liens securing the notes and the guarantees are contractually subordinated to our and our guarantors, existing and future obligations under our revolving credit facility and certain other permitted liens to the extent of the value of the collateral securing such obligations.

The liens securing the indebtedness evidenced by the notes and the guarantees are contractually subordinated, pursuant to the terms of the Intercreditor Agreement, to all of our and the guarantors' existing and future obligations under our revolving credit facility and certain other permitted liens, to the extent of the collateral securing such obligations. Obligations outstanding under our revolving credit facility (including hedges entered into in connection therewith) are secured by a first-priority security interest on the collateral. Although the notes will rank equally in right of payment with all of our existing and future obligations under our revolving credit facility, pursuant to the terms of the Intercreditor Agreement all proceeds of collateral realized after an event of default are required to be applied first to the satisfaction of our priority lien debt until repaid in full.

The value of the collateral securing the notes may not be sufficient to ensure repayment of the notes because the holders of our revolving credit facility debt, other first-priority lien obligations and second-priority lien obligations will be paid first from the proceeds of the collateral.

Our indebtedness and other obligations under our revolving credit facility are secured by a first-priority lien, and our indebtedness and other obligations under the indenture governing our Second Lien Notes are secured by a second-priority lien, on the collateral securing the notes. The liens securing the notes and the guarantees are contractually subordinated to the liens securing obligations under our revolving credit facility, our Second Lien Notes and other priority lien obligations, so that proceeds of the collateral will be applied first to repay those obligations before we use any such proceeds to pay any amounts due on the notes. Accordingly, if we default on the notes, we cannot assure you that the trustee would receive enough money from the sale of the collateral to repay you. In addition, we have specified rights to issue additional notes and other parity lien obligations that would be secured by liens on the collateral on an equal and ratable basis with the notes issued in this offering. If the proceeds of any sale of the collateral are not sufficient to repay all amounts due on the notes, then your claims against our remaining assets to repay any amounts still outstanding under the notes would be unsecured.

The collateral has not been appraised in connection with this offering. Our revolving credit facility permits us to incur additional indebtedness thereunder, and the indenture governing the notes permits us to incur additional obligations secured by liens that have priority over the notes in certain circumstances. The value of the collateral at any time will depend on market and other economic conditions, including the availability of suitable buyers for the collateral. The value of the assets pledged as collateral for the notes could be impaired in the future as a result of changing economic conditions, commodity prices, competition or other future trends. Likewise, we cannot assure you that

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the pledged assets will be saleable or, if saleable, that there will not be substantial delays in their liquidation.

In addition, the collateral securing the notes is subject to other liens permitted under the terms of the indenture and the Intercreditor Agreement, whether arising on or after the date the notes are issued. To the extent that third parties hold prior liens, such third parties may have rights and remedies with respect to the property subject to such liens that, if exercised, could adversely affect the value of the collateral securing the notes. The indenture does not require that we maintain the current level of collateral or maintain a specific ratio of indebtedness to asset values.

With respect to some of the collateral, the collateral trustee's security interest and ability to foreclose on the collateral is also limited by the need to meet certain requirements, such as obtaining third party consents, paying court fees that may be based on the principal amount of the parity lien obligations and making additional filings. If we are unable to obtain these consents, pay such fees or make these filings, the security interests may be invalid and the applicable holders and lenders will not be entitled to the collateral or any recovery with respect thereto. We cannot assure you that any such required consents, fee payments or filings can be obtained on a timely basis or at all. These requirements may limit the number of potential bidders for certain collateral in any foreclosure and may delay any sale, either of which events may have an adverse effect on the sale price of the collateral. Therefore, the practical value of realizing on the collateral may, without the appropriate consents, fees and filings, be limited.

In the event of a foreclosure on the collateral under our revolving credit facility (or a distribution in respect thereof in a bankruptcy or insolvency proceeding), the proceeds from the collateral may not be sufficient to satisfy the notes and other parity lien obligations because such proceeds would, under the Intercreditor Agreement, first be applied to satisfy our obligations under our revolving credit facility, our Second Lien Notes or other priority lien obligations. Only after all of our obligations under our revolving credit facility, our Second Lien Notes and such other obligations have been satisfied will proceeds from the collateral under our revolving credit facility be applied to satisfy our obligations under the notes and other parity lien obligations. In addition, in the event of a foreclosure on the collateral, the proceeds from such foreclosure may not be sufficient to satisfy our obligations under the notes and other parity lien obligations.

Pursuant to the terms of the indenture governing the notes, we and our restricted subsidiaries may sell assets so long as such sales comply with the asset sales covenant or any other applicable provision of the indenture. Upon any such sale, all or a portion of the interest in any asset sold may no longer constitute collateral. Although we may seek to reinvest proceeds from any asset sales, any assets in which we reinvest may not constitute collateral or be as profitable to us as the assets sold.

The equity interests in our subsidiaries pledged as part of the collateral to secure the notes may also have limited value at the time of any attempted realization. In particular, in any bankruptcy or similar proceeding, all obligations of the entity whose equity interest has been pledged must be satisfied before any value will be available to the owner of or the creditor secured by such equity interest. If any subsidiary whose equity interest has been pledged as part of the collateral has liabilities that exceed its assets, there may be no remaining value in such subsidiary's equity interest.

The collateral securing the notes and related guarantees may be diluted under certain circumstances.

The indenture governing our notes and agreements governing our revolving credit facility permit us to incur additional secured indebtedness, including additional notes subject to our compliance with the restrictive covenants in the indenture governing the notes and the agreements governing our revolving credit facility at the time we incur such additional secured indebtedness.

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Any additional notes issued under the indenture governing the notes would be guaranteed by the same guarantors and would have the same security interests, with the same priority, as the notes offered hereby. As a result, the collateral securing the notes would be shared by any additional notes we may issue under the applicable indenture, and an issuance of such additional notes would dilute the value of the collateral compared to the aggregate principal amount of notes issued.

The realizable value of our proved reserves may not be sufficient to pay the notes and other future parity obligations in full after repayment of all priority lien obligations.

Proved reserves constitute a substantial portion of the value of the collateral securing the notes and priority lien obligations. The PV-10 of our proved reserves estimated at December 31, 2014 may significantly exceed the realizable fair market value of such reserves. Our estimated proved reserves as of December 31, 2014 and related PV-10 and Standardized Measure were calculated under SEC rules using twelve-month trailing average benchmark commodity prices, which are substantially above recent WTI spot oil and HH natural gas prices. There is no assurance that oil and natural gas prices will not decline further and our ability to hedge against future commodity price declines may be significantly limited in time and price. Using more recent prices in estimating proved reserves would likely result in a reduction in proved reserve volumes as determined under SEC rules due to economic limits, which would further reduce PV-10 of our proved reserves. In addition, sustained periods with oil and natural gas prices at recent or lower levels and the resultant impact such prices may have on our drilling economics and our ability to raise capital would likely require us to re-evaluate and postpone or eliminate our development drilling, which would likely result in the reduction of some of our proved undeveloped reserves and related PV-10.

Under the indenture, we could incur a substantial amount of additional priority lien obligations and parity lien obligations. In the event of a default or liquidation, there may not be sufficient realizable value of proved reserves to first repay all priority lien obligations outstanding at such time and then repay the notes and any other outstanding parity obligations.

The provisions of the Intercreditor Agreement relating to the collateral securing the notes limit the rights of holders of the notes with respect to that collateral, even during an event of default.

Under the Intercreditor Agreement, the parties are generally entitled to receive and apply all proceeds of any collateral to the repayment in full of the obligations under our revolving credit facility and our Second Lien Notes before any such proceeds will be available to repay obligations under the notes. In addition, the priority lien collateral agent is generally entitled to sole control of all decisions and actions, including foreclosure, with respect to collateral, even if an event of default under the notes has occurred, and neither the holders of notes nor the collateral trustee is generally entitled to independently exercise remedies with respect to the collateral until specified time periods have elapsed, if at all. In addition, the priority lien collateral agent is entitled, without the consent of holders of notes or the collateral trustee, to amend the terms of the security documents securing the notes and to release the liens of the secured parties on any part of the collateral in certain circumstances. Please read "Description of New Notes The Intercreditor Agreement." Furthermore, because the holders of priority lien obligations control the disposition of the collateral securing such first-priority obligations and the notes, if there were an event of default under the notes, the holders of the first-priority obligations can decide, for a specified time period, not to proceed against the collateral, regardless of whether or not there is a default under such first-priority obligations. During such time period, unless and until discharge of the first-priority obligations, including our revolving credit facility, has occurred, the sole right of the holders of the notes would be to hold a lien on the collateral.

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Security over certain collateral on which a lien in favor of the collateral trustee is required, may not have been perfected on the issue date.

Security interests over certain collateral, including mortgages on oil and gas properties, which are required under the indenture governing the notes, may not have been perfected on the Issue Date. To the extent such security interests were not perfected on the Issue Date, we would have been required to have such security interests thereafter perfected promptly, but in no event later than the date that is 30 days after the Issue Date. In the event that more than a reasonable time passes between the issuance of the notes and the perfection of the security interests on the oil and gas properties, such security interests may be set aside or avoided as a preferential transfer if the owner of the collateral becomes a debtor that is the subject of a voluntary or involuntary bankruptcy case under the U.S. Bankruptcy Code (or under certain similar state law insolvency proceedings) on or before 90 days from the perfection of the security interests. In the event of such a determination in such bankruptcy case or insolvency proceeding, the collateral trustee will not have a perfected security interest in that collateral. Recordation of the mortgages after the issuance date of the notes materially increases the risk that the liens granted by those mortgages could be avoided, in the event of such a bankruptcy.

The collateral will be subject to casualty risks.

We are obligated under the indenture and collateral arrangements governing the notes to maintain adequate insurance or otherwise insure against hazards as is customarily done by companies having assets of a similar nature in the same or similar localities. There are, however, certain losses that may be either uninsurable or not economically insurable, in whole or in part. As a result, it is possible that the insurance proceeds will not compensate us fully for our losses. If there is a total or partial loss of any of the collateral, we cannot assure you that any insurance proceeds received by us or any of the subsidiary guarantors will be sufficient to satisfy all of our obligations, including the notes. We may be required to apply the proceeds from any such loss to repay our obligations under our revolving credit facility.

Rights of holders of notes in the collateral may be adversely affected by bankruptcy proceedings.

The right of the collateral trustee to repossess and dispose of the collateral upon acceleration is likely to be significantly impaired by federal bankruptcy law if bankruptcy proceedings are commenced in the United States by or against us prior to or possibly even after the collateral trustee has repossessed and disposed of the collateral. Under the U.S. Bankruptcy Code, a secured creditor, such as the collateral trustee for the holders of the notes, is prohibited from repossessing its security from a debtor, such as us, in a bankruptcy case, or from disposing of security repossessed from a debtor, without bankruptcy court approval. Moreover, bankruptcy law permits the debtor to continue to retain and to use collateral, and the proceeds, products, rents or profits of the collateral, even though the debtor is in default under the applicable debt instruments, provided that the secured creditor is given "adequate protection." The meaning of the term "adequate protection" may vary according to circumstances, but it is intended in general to protect the value of the secured creditor's interest in the collateral and may include cash payments or the granting of additional security, if and at such time as the court in its discretion determines, for any diminution in the value of the collateral as a result of the stay of repossession or disposition or any use of the collateral by the debtor during the pendency of the bankruptcy case. In light of the broad discretionary powers of a bankruptcy court, it is impossible to predict how long payments under the notes could be delayed following commencement of a bankruptcy case, whether or when the collateral trustee would repossess or dispose of the collateral, and whether or to what extent holders of the notes would be compensated for any delay in payment of loss of value of the collateral through the requirements of "adequate protection." Furthermore, in the event the bankruptcy court determines that the value of the collateral is not sufficient to repay all amounts due under the revolving credit facility and on the parity lien obligations, the holders of the notes would

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have "undersecured claims." Federal bankruptcy laws do not permit the payment or accrual of interest, costs and attorneys' fees for "undersecured claims" during the debtor's bankruptcy case. Additionally, the collateral trustee's ability to foreclose on the collateral on your behalf may be subject to the consent of third parties, prior liens and practical problems associated with the realization of the collateral trustee's security interest in the collateral. The debtor or trustee in a bankruptcy case may seek to void an alleged security interest in collateral for the benefit of the bankruptcy estate, and it may be able to successfully do so if the security interest is not properly perfected or was perfected within a specified period of time (generally 90 days) prior to the initiation of such proceeding. If the security interest is avoided, a creditor may hold no security interest and be treated as holding a general unsecured claim in the bankruptcy case. It is impossible to predict what recovery (if any) would be available for such an unsecured claim if we became a debtor in a bankruptcy case. While U.S. bankruptcy law generally invalidates provisions restricting a debtor's ability to assume and/or assign a contract, there are exceptions to this rule which could be applicable in the event that we become subject to a U.S. bankruptcy proceeding.

In addition, a bankruptcy court may decide to substantively consolidate us and some or all of our subsidiaries in the bankruptcy proceeding. If a bankruptcy court substantively consolidated us and some or all of our subsidiaries, the assets of each entity would become subject to the claims of creditors of all entities. Such a ruling would expose holders of notes not only to the usual impairments arising from bankruptcy, but also to potential dilution of the amount ultimately recoverable because of the larger creditor base. Furthermore, a forced restructuring of the notes could occur through the "cramdown" provisions of the U.S. Bankruptcy Code. Under those provisions, the notes could be restructured over holders' objections as to their interest rate, maturity and other general terms.

Any future pledge of collateral may be avoidable in bankruptcy.

Any future pledge of collateral in favor of the collateral agent, including pursuant to security documents delivered after the date of the indenture governing the notes, may be avoidable by the pledgor (a debtor in possession) or by its trustee in bankruptcy under U.S. law if certain events or circumstances exist or occur, including, among others, if:

- the pledgor is insolvent at the time of the pledge;
- the pledge permits the holder of the notes to receive a greater recovery than if the pledge had not been given; and
- a bankruptcy proceeding in respect of the pledgor is commenced within 90 days following the pledge, or, in certain circumstances, a longer period.

The value of the collateral securing the notes may not be sufficient for a bankruptcy court to grant post-petition interest on the notes in a bankruptcy case of the issuer or any of the guarantors. Should our obligations under the notes, together with our obligations under our revolving credit facility, our Second Lien Notes and any other priority lien obligations or parity lien obligations, equal or exceed the fair market value of the collateral securing the notes, the holders of the notes may be deemed to have an unsecured claim for the difference between the fair market value of the collateral, on the one hand, and the aggregate amount of the obligations under our revolving credit facility, any other secured debt and the notes, on the other hand.

In the event of a bankruptcy, liquidation, dissolution, reorganization or similar proceeding against us or the subsidiary guarantors, holders of the notes will be entitled to post-petition interest under the U.S. Bankruptcy Code only if the value of their security interest in the collateral, taken in order of priority with other obligations secured by the collateral, is greater than the amount of their pre-bankruptcy claim. Holders of the notes may be deemed to have an unsecured claim if our obligations under the notes, together with our obligations under our revolving credit facility, the Second Lien Notes and any other priority lien obligations, parity lien obligations or junior lien obligations,

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exceed the fair market value of the collateral securing the notes. Holders of the notes that have a security interest in the collateral with a value less than their pre-bankruptcy claim will not be entitled to post-petition interest under the U.S. Bankruptcy Code. The bankruptcy trustee, the debtor-in-possession or competing creditors could possibly assert that the fair market value of the collateral with respect to the notes on the date of the bankruptcy filing (or on the date of confirmation of a chapter 11 plan) was less than the then-current principal amount of the notes. Upon a finding by a bankruptcy court that the notes are under-collateralized, the claims in the bankruptcy proceeding with respect to the notes would be bifurcated between a secured claim equal to the value of the interest in the collateral and an unsecured claim, and the unsecured claim would not be entitled to the benefits of security in the collateral. Other consequences of a finding of under-collateralization would be, among other things, a lack of entitlement on the part of holders of the notes to receive post-petition interest, fees or expenses and a lack of entitlement on the part of the unsecured portion of the notes to receive other "adequate protection" under U.S. bankruptcy laws. In addition, if any payments of post-petition interest were made at the time of such a finding of under-collateralization, such payments could be re-characterized by the bankruptcy court as a reduction of the principal amount of the secured claim with respect to notes. No appraisal of the fair market value of the collateral securing the notes has been prepared in connection with this offering of the notes and, therefore, the value of the collateral trustee's interests in the collateral may not equal or exceed the principal amount of the notes and other secured claims. We cannot assure you that there will be sufficient collateral to satisfy our and the subsidiary guarantors' obligations under the notes.

Rights of holders of notes in the collateral may be adversely affected by the failure to perfect liens on collateral acquired in the future.

Pursuant to the indenture governing the notes and the collateral documents, subject to certain limited exceptions, our obligations to perfect the liens on the collateral are limited to specified actions. See "Description of New Notes Provisions of the Indenture Relating to Security."

The failure to properly perfect liens on collateral could adversely affect the collateral agent's ability to enforce its rights with respect to the collateral for the benefit of the holders of the notes. In addition, applicable law requires that certain property and rights acquired after the grant of a general security interest or lien can be perfected only at or after the time such property and rights are acquired and identified. There can be no assurance that the trustee or the collateral trustee will monitor, or that we, any subsidiary guarantor will inform the trustee or the collateral trustee of, the future acquisition of property and rights that constitute collateral, and that the necessary action will be taken to properly perfect the security interest in such after acquired collateral. The trustee and the collateral trustee for the notes have no obligation to monitor the acquisition of additional property or rights that constitute collateral or the perfection of any security interests therein. Such failure may result in the loss of the practical benefits of the liens thereon or of the priority of the liens securing the notes against third parties.

There are circumstances other than repayment or discharge of the notes under which the collateral will be released.

Under various circumstances, liens on the collateral securing the notes may be released without your consent, including:

- a sale, transfer or other disposal of such collateral in a transaction not prohibited under the indenture governing the notes and the delivery of a certificate to the collateral trustee;

- with respect to the collateral held by a subsidiary guarantor, upon the release of such subsidiary guarantor from its guarantee;

- to the extent we have defeased or satisfied and discharged the indenture governing the notes;

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- with the consent of the holders of the requisite percentage of notes in accordance with the provisions described under "Description of New Notes Amendments and Waivers"; and

- in other circumstances specified in the Intercreditor Agreement, including in connection with the exercise of remedies by the collateral trustee.

In addition, a guarantee will be automatically released in connection with a sale of such subsidiary guarantor or a sale of all or substantially all of the assets of that subsidiary guarantor, in each case, in a transaction not prohibited under the indenture governing the notes.

We may not be able to repurchase the notes upon a change of control.

Upon the occurrence of a change of control (as defined in the indenture governing the notes), unless we exercise our change of control redemption right (as described in "Description of New Notes Optional Redemption"), we will be required to make an offer to repurchase all outstanding notes at 101% of their principal amount, plus accrued and unpaid interest. The holders of the Second Lien Notes, our outstanding 2020 Senior Notes and 2021 Senior Notes have substantially the same right. We may not be able to repurchase the notes upon a change of control because we may not have sufficient funds and our credit facility may restrict us from making such a repurchase. Accordingly, we may not be able to satisfy our obligations to purchase your notes unless we are able to refinance or obtain waivers under our credit facility or other senior debt, as applicable. Our failure to repurchase the notes upon a change of control would cause a default under the indenture governing the notes and a cross-default under our credit facility. Our credit facility also provides that a change of control, as defined in our credit facility, will be an event of default that permits lenders to accelerate the maturity of borrowings under the agreement and, if that debt is not paid, to enforce security interests in the collateral securing that debt, thereby limiting our ability to raise cash to purchase the notes, and reducing the practical benefit of the offer-to-purchase provisions to the holders of the notes. Accordingly, to avoid the obligation to repurchase the notes, events of default and potential breaches of our credit facility, we may decline business opportunities that could involve a change of control that would otherwise be beneficial to us.

You may not be able to determine when a change of control giving rise to your right to have the notes repurchased by us has occurred following a sale of "substantially all" of our assets.

A change of control, as defined in the indenture governing the notes, will require us to make an offer to repurchase all notes. The definition of change of control includes a phrase relating to the sale, lease or transfer of "all or substantially all" of our assets. There is no precisely established definition of the phrase "substantially all" under applicable law. Accordingly, the ability of a holder of notes to require us to repurchase their notes as a result of a sale, lease or transfer of less than all of our assets to another individual, group or entity may be uncertain.

Many of the covenants contained in the indenture will be suspended if the notes are rated investment grade by both S&P and Moody's and no default has occurred and is continuing.

Many of the covenants in the indenture governing the notes will be suspended if the notes are rated investment grade by both S&P and Moody's, provided at such time no default with respect to the notes has occurred and is continuing. There can be no assurance that the notes will ever be rated investment grade, or that if they are rated investment grade, that the notes will maintain such ratings. However, suspension of these covenants would allow us to engage in certain transactions that would not be permitted while these covenants were in force. See "Description of New Notes Certain Covenants Covenant Suspension."

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Any guarantees by our subsidiaries of the notes could be deemed fraudulent conveyances under certain circumstances, and a court may try to subordinate or void these subsidiary guarantees.

Under U.S. bankruptcy law and comparable provisions of state fraudulent transfer laws, a guarantee can be voided, or claims under a guarantee may be subordinated to all other debts of that guarantor if, among other things, the guarantor, at the time it incurred the indebtedness evidenced by its guarantee:

- intended to hinder, delay or defraud any present or future creditor or received less than reasonably equivalent value or fair consideration for the incurrence of the guarantee;
- was insolvent or rendered insolvent by reason of such incurrence;
- was engaged in a business or transaction for which the guarantor's remaining assets constituted unreasonably small capital; or
- intended to incur, or believed that it would incur, debts beyond its ability to pay those debts as they mature.

In addition, any payment by that guarantor under a guarantee could be voided and required to be returned to the guarantor or to a fund for the benefit of the creditors of the guarantor. The measures of insolvency for purposes of these fraudulent transfer laws will vary depending upon the law applied in any proceeding to determine whether a fraudulent transfer has occurred.

Generally, however, a subsidiary guarantor would be considered insolvent if:

- the sum of its debts, including contingent liabilities, was greater than the fair saleable value of all of its assets;
- the present saleable value of its assets was less than the amount that would be required to pay its probable liability, including contingent liabilities, on its existing debts as they become absolute and mature; or
- it could not pay its debts as they became due.

Your ability to transfer the notes may be limited by the absence of an active trading market, and there is no assurance that any active trading market will develop for the notes.

The notes are new issues of securities for which there is no established public market. We do not intend to have the notes listed on a national securities exchange or to arrange for quotation on any automated dealer quotation systems. We cannot assure you that an active trading market for the notes will develop or, if developed, that it will continue. In that case, the holders of the notes may not be able to sell their notes at a particular time or at a favorable price. The liquidity of any market for the notes will depend on a number of factors, including:

- the number of holders of notes;
- our operating performance and financial condition;
- the market for similar securities;

- the interest of securities dealers in making a market in the notes; and

- prevailing interest rates.

Even if an active trading market for the notes does develop, there is no guarantee that it will continue. Historically, the market for non-investment grade debt, such as the notes, has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes. We cannot assure you that the market, if any, for the notes will be free from similar disruptions or that any such disruptions may not adversely affect the prices at which you may sell your notes.

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We may be unable to repay or repurchase the notes at maturity.

At maturity, the entire outstanding principal amount of the notes, together with accrued and unpaid interest, will become due and payable. We may not have the funds to fulfill these obligations or the ability to renegotiate these obligations. If upon the maturity date other arrangements prohibit us from repaying the notes, we could try to obtain waivers of such prohibitions from the lenders and holders under those arrangements, or we could attempt to refinance the borrowings that contain the restrictions. In these circumstances, if we were not able to obtain such waivers or refinance these borrowings, we would be unable to repay the notes.

Liquidity concerns could result in a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

A downgrade, suspension or withdrawal of the rating assigned by a rating agency to our company or the notes, if any, could cause the liquidity or market value of the notes to decline.

Credit rating agencies continually revise their ratings for the companies that they follow, including us. The credit rating agencies also evaluate our industry as a whole and may change their credit ratings for us based on their overall view of the industry. In addition, the notes have been rated by Moody's and S&P and may in the future be rated by additional rating agencies. We cannot assure you that any rating assigned will remain for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in that rating agency's judgment, circumstances relating to the basis of the rating, such as adverse changes in our business, so warrant. Any downgrade, suspension or withdrawal of a rating by a rating agency of us or the notes (or any anticipated downgrade, suspension or withdrawal) could reduce the liquidity or market value of the notes. Any future lowering of our ratings or the ratings of the notes may make it more difficult or more expensive for us to obtain additional debt financing. If any credit rating initially assigned to the notes is subsequently lowered or withdrawn for any reason, or there is a negative change to our ratings, you may lose some or all of the value of your investment in the notes.

The market price for the notes may be volatile.

Historically, the market for non-investment grade debt has been subject to disruptions that have caused substantial volatility in the prices of securities similar to the notes. The market for the notes, if any, may be subject to similar disruptions. Any such disruptions may adversely affect the value of your notes. In addition, subsequent to their initial issuance, the notes may trade at a discount from their initial offering price, depending upon prevailing interest rates, the market for similar notes, our performance and other factors.

Risks Related to the Oil and Gas Industry and Our Business

Due to reduced commodity prices and lower operating cash flows, coupled with substantial interest payments, there is doubt about our ability to maintain adequate liquidity through 2015 and our ability to make interest payments in respect of our indebtedness.

During the past year, NYMEX-WTI oil prices fell from in excess of $100 per Bbl to below $50 per Bbl, the lowest price since 2009. The substantial reduction in oil and NGL prices has caused a reduction in our forecast of available liquidity and we may not have the ability to maintain our current borrowing base under our reserve based credit facility at its current levels or generate sufficient cash flows from operations and, therefore, sufficient liquidity to meet our anticipated working capital, debt service and other liquidity needs. A sustained material decline in oil, NGL and natural gas prices or a reduction in our oil and natural gas production and reserves would reduce our ability to fund our capital expenditure program and negatively impact our liquidity on an ongoing basis.

Our substantial indebtedness, liquidity issues and potential to seek restructuring transactions may have a material adverse effect on our business and operations.

Our substantial indebtedness, liquidity issues and potential to seek restructuring transactions may result in uncertainty about our business and cause, among other things:

- third parties' to lose confidence in our ability to explore and produce oil and natural gas, resulting in a significant decline in our revenues, profitability and cash flow;
- difficulty retaining, attracting or replacing key employees;
- employees to be distracted from performance of their duties or more easily attracted to other career opportunities; and
- our suppliers, vendors, hedge counterparties and service providers to renegotiate the terms of our agreements, terminate their relationship with us or require financial assurances from us.

These events may have a material adverse effect on our business and operations.

If we are unable to repay or refinance our existing and future debt as it becomes due, we may be unable to continue as a going concern.

Our existing and future debt agreements could create issues as interest payments become due and the debt matures that will threaten our ability to continue as a going concern. For example, absent any action with respect to the repayment or refinancing of our existing indebtedness or any waivers or amendments to the agreements governing our existing indebtedness, our reserve based revolving credit facility is scheduled to mature in 2018 and our senior notes are scheduled to mature in 2020 and 2021. Additionally, the borrowing base under our reserve based revolving credit facility is subject to at least semi-annual redetermination and as a result, availability thereunder could be reduced and advances in excess of the new availability would need to be repaid. We have substantial interest payments due during the next twelve months. If we fail to satisfy our obligations with respect to our indebtedness or fail to comply with the financial and other restrictive covenants contained in the revolving credit facility, the indentures governing our senior notes, or other agreements governing our indebtedness, an event of default could result, which would permit acceleration of such debt and which could result in an event of default under and acceleration of our other debt and could permit our secured lenders to foreclose on any of our assets securing such debt. Any accelerated debt would become immediately due and payable. While we will attempt to take appropriate mitigating actions to refinance any indebtedness prior to its maturity or otherwise extend the maturity dates, and to cure any potential defaults, there is no assurance that any particular actions with respect to refinancing existing indebtedness, extending the

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maturity of existing indebtedness or curing potential defaults in our existing and future debt agreements will be sufficient.

The consolidated financial statements included in this prospectus have been prepared on a going concern basis of accounting, which contemplates continuity of operations, realization of assets, and satisfaction of liabilities and commitments in the normal course of business. The consolidated financial statements do not reflect any adjustments that might result if we are unable to continue as a going concern.

A substantial or extended decline in oil and, to a lesser extent, natural gas, prices may adversely affect our business, financial condition or results of operations and our ability to meet our capital expenditure obligations and financial commitments.

The price we receive for our oil and, to a lesser extent, natural gas, heavily influences our revenue, profitability, access to capital and future rate of growth. Oil and natural gas are commodities and, therefore, their prices are subject to wide fluctuations in response to relatively minor changes in supply and demand. Historically, the markets for oil and natural gas have been volatile. The spot natural gas prices during 2014 ranged from a high of $8.15 to a low of $2.99 per MMBtu and the spot oil prices during 2014 ranged from a high of $107.95 to a low of $53.45 per Bbl. Thus far in 2015, commodity prices have continued to be depressed and volatile. These markets will likely continue to be volatile in the future.

The prices we receive for our production and the levels of our production depend on numerous factors beyond our control. These factors include the following:

- worldwide and regional economic conditions impacting the global supply and demand for oil and natural gas;
- the actions of the Organization of Petroleum Exporting Countries;
- the price and quantity of imports of foreign oil and natural gas;
- political conditions in or affecting other oil and natural gas-producing countries;
- the level of global oil and natural gas exploration and production;
- the level of global oil and natural gas inventories;
- localized supply and demand fundamentals and transportation availability;
- weather conditions and natural disasters;
- domestic, local and foreign governmental regulations and taxes;
- speculation as to the future price of oil and natural gas and the speculative trading of oil and natural gas futures contracts;
- price and availability of competitors' supplies of oil and natural gas;
- technological advances affecting energy consumption; and

- the price and availability of alternative fuels.

Substantially all of our production is currently sold to purchasers under short-term (less than 12-month) contracts at market based prices. Lower oil and natural gas prices will reduce our cash flows, borrowing ability and the present value of our reserves. If oil and natural gas prices deteriorate, we anticipate that the borrowing base under our revolving credit facility, which is revised periodically, may be reduced. Lower oil and natural gas prices may also reduce the amount of oil and natural gas that we can produce economically. Substantial decreases in oil and natural gas prices could render

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uneconomic a significant portion of our identified drilling locations. This may result in our having to make significant downward adjustments to our estimated proved reserves. As a result, a substantial or extended decline in oil or natural gas prices may materially and adversely affect our future business, financial condition, results of operations, liquidity or ability to finance planned capital expenditures.

We may not be able to obtain funding under our revolving credit facility because of a decrease in our borrowing base or obtain funding in the capital markets on terms we find acceptable.

Historically, we have used our cash flows from operations and borrowings under our revolving credit facility to fund our capital expenditures and have relied on the capital markets and asset monetization transactions to provide us with additional capital for large or exceptional transactions or to refinance debt obligations. At June 30, 2015, we had no amounts drawn on the credit facility and had outstanding letters of credit obligations totaling $1.5 million. The borrowing base under our revolving credit facility is subject to semiannual redeterminations in April and October and up to one additional time per six month period following each scheduled borrowing base redetermination, as may be requested by us or the administrative agent, acting on behalf of lenders holding at least two-thirds of the outstanding loans and other obligations. Should prices for oil and natural gas remain weak or deteriorate, if we have a downward revision in estimates of our proved reserves, or if we sell oil and natural gas reserves, our borrowing base may be reduced. Any reduction in the borrowing base will reduce our available liquidity, and, if the reduction results in the outstanding amount under the facility exceeding the borrowing base, we will be required to repay the deficiency within 30 days or in six equal monthly installments thereafter, at our election. We may not have the financial resources in the future to make any mandatory deficiency principal prepayments required under our revolving credit facility, which could result in an event of default.

In the future, we may not be able to access adequate funding under our revolving credit facility as a result of (i) a decrease in our borrowing base due to the outcome of a subsequent borrowing base redetermination, or (ii) an unwillingness or inability on the part of our lending counterparties to meet their funding obligations. Since the process for determining the borrowing base under our revolving credit facility involves evaluating the estimated value of some of our oil and natural gas properties using pricing models determined by the lenders at that time, a decline in those prices used, or further downward reductions of our reserves, likely will result in a redetermination of our borrowing base and a decrease in the available borrowing amount at the time of the next scheduled redetermination. In such case, we would be required to repay any indebtedness in excess of the borrowing base.

Volatility in the public and private capital markets may make it more difficult to obtain funding. There is a risk that the cost of obtaining money from the credit markets may increase in the future as lenders and institutional investors may increase interest rates, impose tighter lending standards, refuse to refinance existing debt at maturity on terms similar to existing debt or at all, or reduce or cease to provide any new funding. Due to these factors, we cannot be certain that funding, if needed, will be available to the extent required, or on acceptable terms. If we are unable to access funding when needed on acceptable terms, we may not be able to fully implement our business plans, take advantage of business opportunities, respond to competitive pressures, or refinance our debt obligations as they come due, any of which could have a material adverse effect on our operations and financial results.

Our ability to access funds under our revolving credit facility is based on a borrowing base, which is subject to periodic redeterminations based on our proved reserves and commodity prices that will be determined by our lenders using the bank pricing prevailing at such time.

Our level of indebtedness may increase and reduce our financial flexibility.

As of June 30, 2015, we had $250.9 million available and a borrowing base of $252.4 million under our revolving credit facility, $293.6 million in 2020 Senior Notes, $347.7 million in 2021 Senior Notes,

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$625.0 million in Second Lien Notes and $524.121 million in Third Lien Notes outstanding. In the future, we may incur significant additional indebtedness in order to make future acquisitions or to develop our properties.

Our current level of indebtedness could affect our operations in several ways, including the following:

- causing a significant portion of our cash flows to be used to service our indebtedness, thereby reducing the availability of cash flows for working capital, capital expenditures and other general business activities;
- increasing our vulnerability to general adverse economic and industry conditions;
- limiting our ability to borrow additional funds, dispose of assets, pay dividends and make certain investments;
- placing us at a competitive disadvantage compared to our competitors that are less leveraged and, therefore, such competitors may be able to take advantage of opportunities that our indebtedness would prevent us from pursuing;
- causing our debt covenants to affect our flexibility in planning for, and reacting to, changes in the economy and in our industry;
- making it more likely that a reduction in our borrowing base following a periodic redetermination could require us to repay a portion of our then outstanding bank borrowings;
- impairing our ability to obtain additional financing in the future for working capital, capital expenditures, acquisitions, general corporate or other purposes; and
- making it more difficult for us to satisfy our obligations under the indentures governing our Senior Notes.

A high level of indebtedness increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of indebtedness depends on our future performance. General economic conditions, oil and natural gas prices and financial, business and other factors affect our operations and our future performance. Many of these factors are beyond our control.

If we are unable to repay our debt out of our cash on hand, we could attempt to refinance such debt, obtain additional borrowings, sell assets or repay such debt with the proceeds from an equity offering. We cannot assure you that refinancing, additional borrowings, proceeds from the sale of assets or equity financing will be available to pay or refinance such debt. Factors that may affect our ability to raise cash through an offering of our capital stock, a refinancing of our debt or a sale of assets include financial market conditions, our market value, our reserve levels and our operating performance at the time of such offering or other financing. The inability to repay or refinance our debt could have a material adverse effect on our operations and could result in a reduction in our capital program or lead us to pursue other alternatives to develop our assets.

In addition, our bank borrowing base is subject to periodic redeterminations on a semi-annual basis, effective October 1 and April 1 and up to one additional time per six-month period following each scheduled borrowing base redetermination, as may be requested by either us or the administrative agent under our revolving credit facility. In the future we could be forced to repay a portion of our then outstanding bank borrowings due to future redeterminations of our borrowing base. If we are forced to do so, we may not have sufficient funds to make such repayments. If we do not have sufficient funds and are unable to arrange new financing, we may have to sell significant assets. Any such sale could have a material adverse effect on our business and financial results.

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Our revolving credit facility and the indentures governing our Senior Notes contains certain covenants that may inhibit our ability to make certain investments, incur additional indebtedness and engage in certain other transactions, which could adversely affect our ability to meet our future goals.

Our revolving credit facility and the indentures governing our Senior Notes includes certain covenants that, among other things, restrict:

- our ability to incur or assume additional debt or provide guarantees in respect of obligations of other persons;
- issue redeemable stock and preferred stock;
- pay dividends or distributions or redeem or repurchase capital stock;
- prepay, redeem or repurchase certain debt;
- make loans and investments;
- create or incur liens;
- restrict distributions from our subsidiaries;
- sell assets and capital stock of our subsidiaries;
- consolidate or merge with or into another entity, or sell all or substantially all of our assets; and
- enter into new lines of business.

A breach of the covenants under the indentures governing the Senior Notes or under the revolving credit facility could result in an event of default under the applicable indebtedness. An event of default may allow the creditors to accelerate the related debt and may result in an acceleration of any other debt to which a cross-acceleration or cross-default provision applies. In addition, an event of default under our credit facility would permit the lenders under the facility to terminate all commitments to extend further credit. If we were unable to repay those amounts, the lenders under our revolving credit facility could proceed against the collateral granted to them to secure that debt.

In addition, our revolving credit facility requires us to maintain certain financial ratios, including a leverage ratio. All of these restrictive covenants may restrict our ability to expand or pursue our business strategies. Our ability to comply with these and other provisions of our revolving credit facility may be impacted by changes in economic or business conditions, results of operations or events beyond our control. The breach of any of these covenants could result in a default under our revolving credit facility, in which case, depending on the actions taken by the lenders thereunder or their successors or assignees, such lenders could elect to declare all amounts borrowed under our revolving credit facility, together with accrued interest, to be due and payable. If we were unable to repay such borrowings or interest, our lenders could proceed against their collateral. If the indebtedness under our revolving credit facility were to be accelerated, our assets may not be sufficient to repay in full such indebtedness.

We may be unable to maintain compliance with certain financial ratio covenants of our outstanding indebtedness which could result in an event of default that, if not cured or waived, would have a material adverse effect on our business, financial condition and results of operations.

Our revolving credit facility requires us to maintain certain financial ratios or to reduce our indebtedness if we are unable to comply with such ratios. As of June 30, 2015 we are in compliance with our financial covenants; however, we cannot guarantee that we will be able to comply with such terms at all times in the future. Any failure to comply with the conditions and covenants in our revolving credit facility that is not waived by our lenders or otherwise cured could lead to a termination of our revolving credit facility, acceleration of all amounts due under our revolving credit facility, or

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trigger cross-default provisions under other financing arrangements. These restrictions may limit our ability to obtain future financings to withstand a future downturn in our business or the economy in general, or to otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations that the restrictive covenants under our indebtedness impose on us.

Liquidity concerns could result in a downgrade in our debt ratings which could restrict our access to, and negatively impact the terms of, current or future financings or trade credit.

Our ability to obtain financings and trade credit and the terms of any financings or trade credit is, in part, dependent on the credit ratings assigned to our debt by independent credit rating agencies. We cannot provide assurance that any of our current ratings will remain in effect for any given period of time or that a rating will not be lowered or withdrawn entirely by a rating agency if, in its judgment, circumstances so warrant. Factors that may impact our credit ratings include debt levels, planned asset purchases or sales and near-term and long-term production growth opportunities, liquidity, asset quality, cost structure, product mix and commodity pricing levels. A ratings downgrade could adversely impact our ability to access financings or trade credit, increase our borrowing costs and potentially require us to post letters of credit for certain obligations.

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

Our future financial condition and results of operations will depend on the success of our development, drilling and production activities. Our oil and natural gas drilling and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore or develop drilling locations or properties will depend in part on the evaluation of data obtained through 2D and 3D seismic data, geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The production and operating data that is available with respect to our operating areas based on modern drilling and completion techniques is relatively limited compared to trends where multiple operators have been active for a significant period of time. As a result, we face more uncertainty in evaluating data than operators in more developed trends. For a discussion of the uncertainty involved in these processes, see " Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these assumptions will materially affect the quantities and present value of our reserves." Our costs of drilling, completing and operating wells are often uncertain before drilling commences. In addition, the application of new techniques in these trends, such as high-graded stimulation designs and horizontal completions, some of which we may not have previously employed, may make it more difficult to accurately estimate these costs. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical. Further, many factors may curtail, delay or cancel our scheduled drilling projects, including the following:

- shortages of, or delays in, obtaining equipment and qualified personnel;
- facility or equipment malfunctions;
- unexpected operational events;
- pressure or irregularities in geological formations;
- adverse weather conditions;
- reductions in oil and natural gas prices;
- delays imposed by or resulting from compliance with regulatory requirements;

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- proximity to and capacity of transportation facilities;
- title problems; and
- limitations in the market for oil and natural gas.
- cost associated with developing and operating oil and gas properties

In addition, our hydraulic fracturing operations require significant quantities of water. Regions where we operate have recently experienced drought conditions. These conditions could persist in the future, diminishing our access to water for hydraulic fracturing operations. Any diminished access to water for use in hydraulic fracturing, whether due to usage restrictions or drought or other weather conditions, could curtail our operations or otherwise result in delays in operations or increased costs.

The standardized measure of discounted future net cash flows from our proved reserves will not be the same as the current market value of our estimated oil and natural gas reserves. If the standardized measure of discounted future net cash flows was run at current strip prices, our total estimated proved reserves would be significantly below the standardized measure of discounted future net cash flows at December 31, 2014.

You should not assume that the standardized measure of discounted future net cash flows from our proved reserves is the current market value of our estimated oil and natural gas reserves. In accordance with SEC requirements in effect at December 31, 2014, 2013 and 2012, we based the discounted future net cash flows from our proved reserves on the 12-month unweighted arithmetic average of the first-day-of-the-month price for the preceding twelve months without giving effect to derivative transactions. Actual future net cash flows from our oil and natural gas properties will be affected by factors such as:

- actual prices we receive for oil and natural gas;
- actual cost of development and production expenditures;
- the amount and timing of actual production; and
- changes in governmental regulations or taxation.

The timing of both our production and our incurrence of expenses in connection with the development and production of oil and natural gas properties will affect the timing and amount of actual future net revenues from proved reserves, and thus their actual present value. In addition, the 10% discount factor we use when calculating standardized measure may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with us or the oil and natural gas industry in general. Prior to our corporate reorganization in April 2012 in connection with our initial public offering, we were not subject to entity level taxation. Accordingly, our standardized measure for periods prior to such reorganization does not provide for federal or state corporate income taxes because taxable income was passed through to our equity holders. However, as a result of our corporate reorganization, we are now treated as a taxable entity for federal income tax purposes and our income taxes are dependent upon our taxable income. Actual future prices and costs may differ materially from those used in the present value estimates included in this report which could have a material effect on the value of our reserves.

Due to the recent decrease in oil and natural gas prices and if prices continue to decrease, we may be required to take write-downs of the carrying values of our oil and natural gas properties.

We use the full cost method of accounting for our oil and gas properties. Accordingly, we capitalize and amortize all productive and nonproductive costs directly associated with property acquisition, exploration and development activities. Under the full cost method, the capitalized cost of oil and gas properties, less accumulated amortization and related deferred income taxes may not exceed

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the "cost center ceiling" which is equal to the sum of the present value of estimated future net revenues from proved reserves, less estimated future expenditures to be incurred in developing and producing the proved reserves computed using a discount factor of 10%, plus the costs of properties not subject to amortization, plus the lower of the cost or estimated fair value of unproved properties included in the costs being amortized, less related income tax effects. If the net capitalized costs exceed the cost center ceiling, we recognize the excess as an impairment of oil and gas properties. During the six months ended June 30, 2015, we recognized an impairment of $673.1 million, for the amount by which our net capitalized costs exceeded the cost center ceiling. This impairment does not impact cash flows from operating activities but does reduce our earnings and shareholders' equity. The risk that we will be required to recognize impairments of our oil and natural gas properties increases during periods of low commodity prices. In addition, impairments would occur if we were to experience sufficient downward adjustments to our estimated proved reserves or the present value of estimated future net revenues. An impairment recognized in one period will not be reversed in a subsequent period even if higher oil and gas prices increase the cost center ceiling applicable to the subsequent period. We expect to recognize an impairment for the three months ended September 30, 2015, and such impairment is anticipated to be material. We could incur further impairments of oil and natural gas properties in the future, particularly as a result of sustained or further decline in commodity prices.

Oil and natural gas prices are volatile. A substantial portion of our hedges are set to expire in 2015. If we choose not to replace hedges as those contracts expire, our cash flows from operations will be subjected to increased volatility.

We enter into hedging transactions of our oil and natural gas production revenues to reduce our exposure to fluctuations in the price of oil and natural gas. A substantial portion of our hedges are set to expire in 2015. As our hedges expire, more of our future production will be sold at market prices, exposing us to the fluctuations in the price of oil and natural gas, unless we enter into additional hedging transactions. We may choose not to replace existing hedges as those contracts expire, which will subject our cash flows from operations to increased volatility.

We have incurred losses from operations during certain periods since the beginning of 2008 and may continue to do so in the future.

We incurred losses from operations of $407.4 million, $15.6 million and $11.8 million for the years ended December 31, 2013, 2010 and 2009, respectively. Our development of and participation in an increasingly larger number of drilling locations has required and will continue to require substantial capital expenditures. The uncertainty and risks described in this report may impede our ability to economically acquire and develop oil and natural gas reserves. As a result, we may not be able to achieve or sustain profitability or positive cash flows provided by operating activities in the future.

Our estimated proved reserves are based on many assumptions that may turn out to be inaccurate. Any significant inaccuracies in these assumptions will materially affect the quantities and present value of our reserves.

The process of estimating oil and natural gas reserves is complex. It requires interpretations of available technical data and many assumptions, including assumptions relating to current and future economic conditions and commodity prices. Any significant inaccuracies in these assumptions could materially affect the estimated quantities and present value of reserves shown in this report.

In order to prepare our estimates, we must estimate production rates and the timing of development expenditures. We must also analyze available geological, geophysical, production and engineering data. The extent, quality and reliability of this data can vary. The process also requires economic assumptions about matters such as oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. Estimates of oil and natural gas reserves are inherently imprecise. In addition, reserve estimates for properties that do not have a lengthy production history, including the areas in which we operate, are less reliable than estimates for fields with lengthy production histories. There can be no assurance that analysis of previous production data relating to the Mississippian Lime, Anadarko Basin or Upper Gulf Coast Tertiary trend will accurately predict future production, development expenditures or operating expenses from wells drilled and completed using modern techniques. In addition, this data is partially based on vertically drilled wells, which may not accurately reflect production, development expenditures or operating expenses that may result from the application of horizontal drilling techniques.

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

The development of our proved undeveloped reserves in our areas of operation may take longer and may require higher levels of capital expenditures than we currently anticipate. Therefore, our undeveloped reserves may not be ultimately developed or produced.

Approximately 52% of our total estimated proved reserves were classified as proved undeveloped as of December 31, 2014. Development of these reserves may take longer and require higher levels of capital expenditures than we currently anticipate. Delays in the development of our reserves or increases in costs to drill and develop such reserves will reduce the future net revenues estimated for such reserves and may result in some projects becoming uneconomic. In addition, pursuant to existing SEC rules and guidance, subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. Accordingly, delays in the development of such reserves, increases in capital expenditures required to develop such reserves and changes in commodity prices could cause us to have to reclassify our proved undeveloped reserves as unproved reserves, which may materially adversely affect our business, results of operations and financial condition.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our business, financial condition and results of operations.

Unless we conduct successful development and exploration activities or acquire properties containing proved reserves, our proved reserves will decline as those reserves are produced. Producing oil and natural gas reservoirs generally are characterized by declining production rates that vary depending upon reservoir characteristics and other factors. Our future oil and natural gas reserves and production, and therefore our cash flows and income, are highly dependent on our success in efficiently developing our current reserves and economically finding or acquiring additional recoverable reserves. We may not be able to develop, find or acquire additional reserves to replace our current and future production at acceptable costs. If we are unable to replace our current and future production, the value of our reserves will decrease, and our business, financial condition and results of operations will be adversely affected.

Drilling locations that we have identified may not yield oil or natural gas in commercially viable quantities.

We describe some of our drilling locations and our plans to explore those drilling locations in this report. Our drilling locations are in various stages of evaluation, ranging from a location which is ready to drill to a location that will require substantial additional interpretation. There is no way to predict in advance of drilling and testing whether any particular location will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in sufficient quantities to be economically viable. Even if sufficient amounts of oil or natural gas exist, we may damage the potentially productive hydrocarbon bearing formation or experience mechanical difficulties while drilling or completing the well, resulting in a reduction in production from or abandonment of the well. If we drill additional wells that we identify as dry holes in our current and future drilling locations, our drilling success rate may decline and materially harm our business. In sum, the cost of drilling, completing and operating any well is often uncertain, and new wells may not be productive.

Our identified drilling locations are scheduled out over many years, making them susceptible to uncertainties that could materially alter the occurrence or timing of their drilling, which in certain instances could prevent production prior to the expiration date of leases for such locations. In addition, we may not be able to raise the amount of capital that would be necessary to drill a substantial portion of our identified drilling locations.

Our management team has identified and scheduled certain drilling locations as an estimation of our future multi-year drilling activities on our existing acreage and acreage currently under option. These drilling locations represent a significant part of our growth strategy. Our ability to drill and develop these drilling locations depends on a number of uncertainties, including oil and natural gas prices, the availability and cost of capital, drilling and production costs, the availability of drilling services and equipment, drilling results, lease expirations, gathering systems, marketing and pipeline transportation constraints, regulatory approvals and other factors. Because of these uncertain factors, we do not know if the numerous drilling locations we have identified will ever be drilled or if we will be able to produce oil or natural gas from these or any other drilling locations. In addition, unless production is established within the spacing units covering the undeveloped acres on which some of the potential locations are obtained, the leases for such acreage will expire. As such, our actual drilling activities may materially differ from those presently identified.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques. The results of our horizontal drilling activities are subject to drilling and completion technique risks, and actual drilling results may not meet our expectations for reserves or production. As a result, we may incur material impairment of the carrying value of our unevaluated properties, and the value of our undeveloped acreage could decline if drilling results are unsuccessful.

Risks that we face while horizontally drilling include, but are not limited to, landing our well bore in the desired drilling zone, staying in the desired drilling zone while drilling horizontally through the formation, running our casing the entire length of the well bore and being able to run tools and other equipment consistently through the horizontal well bore. Risks that we face while completing our horizontal wells include, but are not limited to, being able to fracture stimulate the planned number of stages, being able to run tools the entire length of the well bore during completion operations and successfully cleaning out the well bore after completion of the final fracture stimulation stage. Ultimately, the success of these horizontal drilling and completion techniques can only be evaluated over time as more wells are drilled in the Mississippian Lime, Anadarko Basin and Upper Gulf Coast Tertiary trend and production profiles are established over a sufficiently long time period. If our horizontal drilling results in these trends are less than anticipated, the return on our investment in this area may not be as attractive as we anticipate. The carrying value of our unevaluated properties could become impaired, which would increase our depletion rate per Boe or result in a ceiling test impairment if there were no corresponding additions to recoverable reserves, and the value of our undeveloped acreage in this area could decline in the future.

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Our business depends on the availability of water and the ability to dispose of water. Limitations or restrictions on our ability to obtain or dispose of water may have an adverse effect on our financial condition, results of operations and cash flows.

With current technology, water is an essential component of drilling and hydraulic fracturing processes. Limitations or restrictions on our ability to secure sufficient amounts of water, or to dispose of or recycle water after use, could adversely impact our operations. In some cases, water may need to be obtained from new sources and transported to drilling sites, resulting in increased costs. Moreover, the introduction of new environmental initiatives and regulations related to water acquisition or waste water disposal, including produced water, drilling fluids and other wastes associated with the exploration, development or production of hydrocarbons, could limit or prohibit our ability to utilize hydraulic fracturing or waste water injection control wells.

In addition, concerns have been raised about the potential for earthquakes to occur from the use of underground injection control wells, a predominant method for disposing of waste water from oil and gas activities. New rules and regulations may be developed to address these concerns, possibly limiting or eliminating the ability to use disposal wells in certain locations and increasing the cost of disposal in our operations. We operate injection wells and utilize injection wells owned by third parties to dispose of waste water associated with our operations.

Compliance with environmental regulations and permit requirements governing the withdrawal, storage, and use of water necessary for hydraulic fracturing of wells or the disposal of water may increase our operating costs or may cause us to delay, curtail or discontinue our exploration and development plans, which could have a material adverse effect on our business, financial condition, results of operations and cash flows.

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

We utilize third-party services to maximize the efficiency of our organization. The cost of oilfield services may increase or decrease depending on the demand for services by other oil and gas companies. There is no assurance that we will be able to contract for such services on a timely basis or that the cost of such services will remain at a satisfactory or affordable level. Shortages or the high cost of frac crews, drilling rigs, equipment, supplies, personnel or oilfield services could delay or adversely affect our development and exploration operations or cause us to incur significant expenditures that are not provided for in our capital budget, which could have a material adverse effect on our business, financial condition or results of operations.

Our business depends on transportation by truck for our oil and condensate production, and our natural gas production depends on transportation facilities that are owned by third parties.

We transport all of our oil and condensate production by truck, which is more expensive and less efficient than transportation via pipeline. Our natural gas production depends in part on the availability, proximity and capacity of pipeline systems and processing facilities owned by third parties. Federal and state regulation of oil and natural gas production and transportation, tax and energy policies, changes in supply and demand, pipeline pressures, damage to or destruction of pipelines and general economic conditions could adversely affect our ability to produce, gather and transport oil and natural gas.

The disruption of third-party facilities due to maintenance, capacity constraints, or weather could negatively impact our ability to market and deliver our products. We have no control over when or if such facilities are restored or what prices will be charged. A total shut-in of production could materially affect us due to a lack of cash flows, and if a substantial portion of the production is hedged at lower than current market prices, those financial hedges would have to be paid from borrowings absent sufficient cash flows.

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Our drilling and production programs may not be able to obtain access on commercially reasonable terms or otherwise to truck transportation, pipelines, gas gathering, transmission, storage and processing facilities to market our oil and gas production.

The marketing of oil and gas production depends in large part on the capacity and availability of trucks, pipelines and storage facilities, gas gathering systems and other transportation, processing and refining facilities. Access to such facilities is, in many respects, beyond our control. If these facilities were unavailable to us on commercially reasonable terms or otherwise, we could be forced to shut in some production or delay or discontinue drilling plans and commercial production following a discovery of hydrocarbons. We rely (and expect to rely in the future) on facilities developed and owned by third parties in order to store, process, transmit and sell our oil and gas production. Our plans to develop and sell our oil and gas reserves could be materially and adversely affected by the inability or unwillingness of third parties to provide sufficient facilities and services to us on commercially reasonable terms or otherwise. The amount of oil and gas that can be produced is subject to limitation in certain circumstances, such as pipeline interruptions due to scheduled and unscheduled maintenance, excessive pressure, physical damage to the gathering, transportation, refining or processing facilities, or lack of capacity on such facilities. The curtailments arising from these and similar circumstances may last from a few days to several months, and in many cases, we may be provided only limited, if any, notice as to when these circumstances will arise and their duration.

We may incur substantial losses and be subject to substantial liability claims as a result of our oil and natural gas operations. Additionally we may not be insured for, or our insurance may be inadequate to protect us against, these risks.

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

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

Any of these risks could adversely affect our ability to conduct operations or result in substantial losses to us as a result of:

- injury or loss of life;
- damage to and destruction of property, natural resources and equipment;
- pollution and other environmental damage;
- regulatory investigations and penalties;

suspension of our operations; and

repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully

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insurable. The occurrence of an event that is not fully covered by insurance could have a material adverse effect on our business, financial condition and results of operations.

We have received a notice of non-compliance with a continued listing standard from The New York Stock Exchange ("NYSE") for our common stock. If we are unable to avoid the delisting of our common stock from the NYSE, it could have a substantial effect on our liquidity and results of operations.

On April 1, 2015, we received notification from the NYSE that the price of our common stock had fallen below the NYSE's continued listing standard. Subsequent to April 1, 2015, we regained compliance with the NYSE continued listing requirement; however on July 16, 2015, we received another notification from the NYSE that the price of our common stock had fallen below the NYSE's continued listing standard. Subsequently, we regained compliance with this continued listing standard. The NYSE requires that the average closing price of a listed company's common stock not be less than $1.00 per share for a period of over 30 consecutive trading days.

Under NYSE rules, a company can avoid delisting if, during the six month period following receipt of the NYSE notice and on the last trading day of any calendar month, a company's common stock price per share and 30 trading-day average share price is at least $1.00. During this six month period, a company's common stock will continue to be traded on the NYSE, subject to compliance with other continued listing requirements. On August 3, the Company announced a 1-for-10 reverse stock split of the Company's common stock to cure the price deficiency, and we subsequently regained compliance within the requisite time period.

On August 13, 2015, we received another notification from NYSE that our market capitalization and last reported stockholders equity had fallen below the NYSE's continued listing standards. The NYSE requires that a listed company's total market capitalization not be less than $50 million for a period of over 30 consecutive trading days and that our last reported stockholder equity not be less than $50 million. In accordance with NYSE procedures, we have 45 days from our receipt of the notice to submit a business plan to the NYSE demonstrating how we intend to regain compliance with the NYSE's continued listing standards within 18 months. The Listings and Compliance Committee of the NYSE (the "Committee") will then review the business plan for final disposition. In the event the Committee accepts the plan, the Company will be subject to quarterly monitoring for compliance with the business plan and the Company's compliance with other NYSE continued listing requirements. In the event the Committee does not accept the business plan, the Company will be subject to delisting procedures and suspension by the NYSE.

The NYSE notifications did not affect our business operations or our SEC reporting requirements and did not conflict with or cause an event of default under any of our material debt or other agreements.

In the future, if our common stock ultimately were to be delisted for any reason, it could negatively impact us by (i) reducing the liquidity and market price of our common stock; (ii) reducing the number of investors willing to hold or acquire our common stock, which could negatively impact our ability to raise equity financing; (iii) limiting our ability to use a registration statement to offer and sell freely tradable securities, thereby preventing us from accessing the public capital markets; and (iv) impairing our ability to provide equity incentives to our employees.

Increased costs of capital could adversely affect our business.

Our business and operating results can be harmed by factors such as the availability, terms and cost of capital, or increases in interest rates. Changes in any one or more of these factors could cause our cost of doing business to increase, limit our access to capital, limit our ability to drill our identified locations and pursue acquisition opportunities, reduce our cash flows available for drilling and place us at a competitive disadvantage. Recent disruptions and continuing volatility in the global financial

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markets may lead to an increase in interest rates or a contraction in credit availability impacting our ability to finance our operations. We require continued access to capital. A significant reduction in the availability of credit could materially and adversely affect our ability to achieve our planned growth and operating results.

We are subject to risks in connection with acquisitions and the integration of significant acquisitions may be difficult.

We have previously acquired reserves, properties, prospects and leaseholds from third parties, including the Eagle Property Acquisition and the Anadarko Basin Acquisition. In addition, we will continue to evaluate other acquisitions of reserves, properties, prospects and leaseholds and other strategic transactions that appear to fit within our overall business strategy. The successful acquisition of assets and other producing properties requires an assessment of several factors, including:

- recoverable reserves;
- future oil and natural gas prices and their appropriate differentials;
- development and operating costs;
- potential for future drilling and production;
- validity of the sellers' title to the properties, which may be less than expected at the time of signing the purchase agreement; and
- potential environmental issues, litigation and other liabilities.

The accuracy of these assessments is inherently uncertain. In connection with these assessments, we perform a review of the subject properties that we believe to be generally consistent with industry practices. Our review will not reveal all existing or potential problems nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and potential recoverable reserves. Inspections may not always be performed on every well, and environmental problems are not necessarily observable even when an inspection is undertaken. Even when problems are identified, the sellers may be unwilling or unable to provide effective contractual protection against all or part of the problems. We often are not entitled to contractual indemnification for environmental liabilities and acquire properties on an "as is" basis.

Significant acquisitions and other strategic transactions may involve other risks, including:

- diversion of our management's attention to evaluating, negotiating and integrating significant acquisitions and strategic transactions;
- the challenge and cost of integrating acquired operations, information management and other technology systems and business cultures with those of our operations while carrying on our ongoing business;
- difficulty associated with coordinating geographically separate organizations;
- an inability to secure, on acceptable terms, sufficient financing that may be required in connection with expanded operations and unknown liabilities; and
- the challenge of attracting and retaining personnel associated with acquired operations.

The process of integrating operations could cause an interruption of, or loss of momentum in, the activities of our business. Members of our senior management may be required to devote considerable amounts of time to this integration process, which will decrease the time they will have to manage our business. If our senior management is not able to effectively manage the integration process, or if any

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significant business activities are interrupted as a result of the integration process, our business could suffer.

In addition, even if we successfully integrate operations acquired in acquisitions, we may not be possible to realize the full benefits we may expect in estimated proved reserves, production volume, cost savings from operating synergies or other benefits anticipated from an acquisition or realize these benefits within the expected time frame. Anticipated benefits of an acquisition may be offset by operating losses relating to changes in commodity prices in oil and natural gas industry conditions, risks and uncertainties relating to the exploratory prospects of the combined assets or operations, failure to retain key personnel, an increase in operating or other costs or other difficulties. We may experience additional challenges integrating the assets of privately operated companies. If we fail to realize the benefits we anticipate from an acquisition, our results of operations and stock price may be adversely affected.

The inability of our significant customers to meet their obligations to us may adversely affect our financial results.

We are subject to credit risk due to concentration of our oil, NGL and natural gas receivables with several significant customers. The largest purchaser of our oil, NGLs and natural gas during the year ended December 31, 2014 was Plains Marketing, L.P., accounting for 28%, and for the year ended December 31, 2013 the largest purchaser was ConocoPhillips, accounting for 28% of our total revenues for these periods. Chevron accounted for 41% of our revenues for the year ended December 31, 2012. We generally do not require our customers to post collateral. The inability or failure of our significant customers to meet their obligations to us or their insolvency or liquidation may adversely affect our financial condition and results of operations.

Our derivative activities could result in financial losses or could reduce our earnings.

To achieve a more predictable cash flow and to reduce our exposure to adverse fluctuations in the prices of oil, we enter into derivative instruments for a portion of our oil, NGL and natural gas production. See "Management's Discussion and Analysis of Financial Condition and Results of Operations Quantitative and Qualitative Disclosures about Market Risk" and Note 5 to our Audited Consolidated Financial Statements for a summary of our oil commodity derivative positions. We did not designate any of our derivative instruments as hedges for accounting purposes, and we record all derivative instruments in our balance sheet at fair value. Changes in the fair value of our derivative instruments are recognized in current earnings. Accordingly, our earnings may fluctuate significantly as a result of changes in the fair value of our derivative instruments.

Derivative instruments expose us to the risk of financial loss in some circumstances, including when:

- production is less than the volume covered by the derivative instruments;
- the counter-party to the derivative instrument defaults on its contractual obligations; or
- there is an increase in the differential between the underlying price in the derivative instrument and actual prices received for basis differentials.

In addition, our derivative arrangements limit the benefit we would receive from increases in the prices for oil, NGLs and natural gas.

Large competitors may be attracted to our core operating areas, which may increase our costs.

Our operations in the Mississippian Lime formation in northwestern Oklahoma, the Anadarko Basin in Texas and Oklahoma and the Upper Gulf Coast tertiary trend in Louisiana may attract

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companies that have greater resources than we do. These companies may be able to pay more for productive oil and natural gas properties and exploratory prospects or identify, evaluate, bid for and purchase a greater number of properties and prospects than our financial or human resources permit. Their presence in our areas of operations may also restrict our access to, or increase the cost of, oil and natural gas infrastructure, drilling rigs, equipment, supplies, personnel and oilfield services, including fracking equipment and crews. In addition, these companies may have a greater ability to continue exploration activities during periods of low oil and natural gas prices. Our larger competitors may be able to absorb the burden of present and future federal, state, local and other laws and regulations more easily than we can, which would adversely affect our competitive position. Our ability to acquire additional properties and to discover reserves in the future will be dependent upon our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. See "Business Competition" for additional discussion of the competitive environment in which we operate.

The volatility in commodity prices and business performance may affect our ability to retain key management. The loss of senior management or technical personnel could adversely affect our operations.

We depend on the services of our senior management and technical personnel. The volatility in commodity prices and business performance may affect our ability to retain key management. The loss of the services of additional members of our senior management or technical personnel could have a material adverse effect on our operations. We do not maintain, nor do we plan to obtain, any insurance against the loss of any of these individuals. Furthermore, if we are unable to find, hire and retain needed key personnel in the future, our business, financial condition and results of operations could be materially and adversely affected.

Title to the properties in which we have an interest may be impaired by title defects.

We do not obtain title insurance and have not necessarily obtained drilling title opinions on all of our oil and natural gas properties. The existence of title deficiencies with respect to our oil and natural gas properties could reduce the value or render such properties worthless, which could have a material adverse effect on our business and financial results. A significant portion of our acreage is undeveloped leasehold acreage, which has a greater risk of title defects than developed acreage. Frequently, as a result of title examinations, certain curative work may be required to correct identified title defects, and such curative work entails time and expense. Our inability or failure to cure title defects could render some locations undrillable or cause us to lose our rights to some or all production from some of our oil and natural gas properties, which could have a material adverse effect on our business and financial results if a comparable additional location to drill a development well cannot be identified.

The proposed U.S. federal budget for fiscal year 2015 and proposed legislation contain certain provisions that, if passed as originally submitted, will have an adverse effect on our financial position, results of operations and cash flows.

The Obama administration's budget proposals for fiscal year 2015 contains numerous proposed tax changes, and from time to time, legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently available to U.S. oil and gas companies. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling and development costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and gas companies; and increase in the geological and geophysical amortization period for independent producers. Should some or all of these provisions become law our taxes could increase, potentially significantly, after net operating losses are exhausted, which would have a negative impact on our net income and cash flows and could reduce our drilling activities. We do not know the ultimate impact these proposed changes may have on our business.

We are subject to various governmental regulations that may cause us to incur substantial costs.

From time to time, in varying degrees, political developments and federal and state laws and regulations affect our operations. In particular, price controls, taxes and other laws relating to the oil and natural gas industry, changes in these laws and changes in administrative regulations have affected, and in the future could affect, oil and natural gas production, operations and economics. We cannot predict how agencies or courts will interpret existing laws and regulations or the effect of these adoptions and interpretations may have on our business or financial condition.

Our business is subject to laws and regulations promulgated by federal, state and local authorities relating to the exploration for, and the development, production and marketing of, oil and natural gas, as well as safety matters. Legal requirements are frequently changed and subject to interpretation, and we are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations. We may be required to make significant expenditures to comply with governmental laws and regulations. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to significant liabilities on our part to the government, and third parties and may require us to incur substantial costs of remediation.

Our sales of oil and gas may expose us to extensive regulation.

The FERC, the Commodity Futures Trading Commission and the Federal Trade Commission hold statutory authority to monitor certain segments of the physical energy commodities markets relevant to our business. These agencies have imposed broad regulations prohibiting fraud and manipulation of such markets. With regard to our physical sales, if any, of oil and gas, we are required to observe the market-related regulations enforced by these agencies.

Our operations are subject to stringent environmental laws and regulations that may expose us to significant costs and liabilities.

Our oil and natural gas exploration, production and development operations are subject to stringent and complex federal, regional, state and local laws and regulations governing the release or disposal of materials into the environment or otherwise relating to environmental protection. These laws and regulations may, among other things, require the acquisition of a permit before drilling commences, restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling, completion and production activities, limit or prohibit construction or drilling activities on certain lands lying within wilderness, wetlands, and other protected areas, and impose substantial liabilities for pollution resulting from our operations. We may be required to make significant capital and operating expenditures to prevent releases, manage wastewater discharges and control air emissions or perform remedial or other corrective actions at our wells and properties to comply with the requirements of these environmental laws and regulations or the terms or conditions of permits issued pursuant to such requirements. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, loss of our leases, incurrence of investigatory or remedial obligations and the issuance of orders limiting or prohibiting some or all of our operations.

There is inherent risk of incurring significant environmental costs and liabilities in the performance of our operations due to our handling of petroleum hydrocarbons and other hazardous substances and wastes, as a result of air emissions and wastewater discharges related to our operations, and because of historical operations and waste disposal practices at our leased and owned properties. Spills or other releases of regulated substances, including such spills and releases that occur in the future, could expose us to material losses, expenditures and liabilities under applicable environmental laws and regulations. Under certain of such laws and regulations, we could be subject to strict, joint and several liability for the removal or remediation of previously released materials or property contamination, regardless of whether we were responsible for the release or contamination and even if our operations met previous standards in the industry at the time they were conducted.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly well drilling, construction, completion or water management activities, air emissions control or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to attain and maintain compliance and may otherwise have a material adverse effect on our industry in general in addition to our own results of operations, competitive position or financial condition. For example, in 2012, the EPA published final rules that subject certain oil and natural gas sources, including production operations, to regulation under the NSPS and NESHAP programs that, among other things, require performance of green completions on certain fractured and re-fractured natural gas wells and establish specific requirements regarding emissions from certain production-related wet seal and reciprocating compressors and from pneumatic controllers and storage vessels. Compliance with these or other new regulations could, among other things, require installation of new emission controls on some of our equipment, result in longer permitting timelines, and significantly increase our expenditures and operating costs, which could adversely impact our business. We may not be able to recover some or any of these costs from insurance.

Climate change legislation or regulations restricting emissions of GHGs could result in increased operating costs and reduced demand for the oil and natural gas we produce.

Based on the EPA's determination that emissions of GHGs present an endangerment to public health and the environment because emissions of such gases are contributing to warming of the earth's atmosphere and other climatic changes, the EPA has regulations under existing provisions of the CAA that, among other things, establish pre-construction and operating permit reviews for GHG emissions from certain large stationary sources that already are potential major sources of certain principal, or criteria, pollutant emissions. Facilities required to obtain permits for their GHG emissions also will be required to meet "best available control technology" standards that typically will be established by the states. In addition, the EPA has adopted regulations requiring the monitoring and annual reporting of GHGs from certain sources in the United States, including, among others, certain onshore and offshore oil and natural gas production facilities.

In addition, the U.S. Congress has from time to time considered adopting legislation to reduce emissions of GHGs and a number of states have already taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or comply with new regulatory or reporting requirements. For example, in January 2015, the Obama Administration announced plans for the EPA to issue final standards in 2016 that would reduce methane emissions from new and modified oil and natural gas production and natural gas processing and transmission facilities by up to 45 percent from 2012 levels by 2025. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the Earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Federal and state legislative and regulatory initiatives relating to hydraulic fracturing as well as governmental reviews of such activities could result in increased costs, additional operating restrictions or delays, which could adversely affect our production.

Hydraulic fracturing is an important and common practice that is used to stimulate production of natural gas and/or oil from dense subsurface rock formations. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely utilize hydraulic fracturing techniques in many of our oil and natural gas drilling and completion programs. The process is typically regulated by state oil and natural gas commissions or similar state agencies, but several federal agencies have asserted regulatory authority over certain aspects of the process. For example, the EPA has issued final CAA regulations governing performance standards, including standards for the capture of air emissions released during hydraulic fracturing; announced its intent to propose in the first half of 2015 effluent limit guidelines that wastewater from shale gas extraction operations must meet before discharging to a treatment plant; and issued in May 2014 a prepublication of its Advance Notice of Proposed Rulemaking regarding Toxic Substances Control Act reporting of the chemical substances and mixtures used in hydraulic fracturing. Also, the BLM issued a revised proposed rule containing disclosure requirements and other mandates for hydraulic fracturing on federal lands and the agency is now analyzing comments to the proposed rulemaking and is expected to promulgate a final rule in the first half of 2015. Compliance with these requirements could increase our costs of development and production, which costs may be significant.

From time to time, Congress has considered legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Moreover, some states, including Louisiana, Texas and Oklahoma, where we operate, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, disclosure and well construction requirements on hydraulic fracturing operations under certain circumstances. States could elect to prohibit hydraulic fracturing altogether, such as the State of New York announced in December 2014. In addition, local government may seek to adopt ordinances within their jurisdictions regulating the time, place and manner of drilling activities in general or hydraulic fracturing activities in particular. If new or more stringent federal, state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, and experience delays or curtailment in the pursuit of exploration, development, or production activities. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

In addition, there are also certain governmental reviews underway that focus on environmental aspects of hydraulic fracturing practices. For example, the White House Council on Environmental Quality is coordinating an administration wide review of hydraulic fracturing practices. Also, the EPA is pursuing a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater and is expected to issue a draft report for public comment and peer review sometime in the first half of 2015. These existing or any future studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or otherwise.

Studies by both state or federal agencies demonstrating a correlation between earthquakes and oil and natural gas activities could result in increased regulatory and operational burdens.

On April 21, 2015, the Oklahoma Geologic Survey ("OGS") issued a document entitled "Statement of Oklahoma Seismicity," in which the agency states "[t]he OGS considers it very likely that the majority of recent earthquakes, particularly those in central and north-central Oklahoma, are

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triggered by the injection of produced water in disposal wells." This development may result in additional levels of regulation, or increased complexity with respect to existing regulations, that could lead to operational delays or increased operating costs and could result in additional regulatory burdens that could make it more difficult to inject produced water into disposal wells, and may increase our costs of compliance and doing business.

Our operations are dependent on our rights and ability to receive or renew the required permits and other approvals from governmental authorities and other third parties.

Performance of our operations require that we obtain and maintain numerous environmental and land use permits and other approvals authorizing our regulated activities. A decision by a governmental authority or other third party to deny, delay or restrictively condition the issuance of a new or renewed permit or other approval, or to revoke or substantially modify an existing permit or other approval, could have a material adverse effect on our ability to initiate or continue operations at the affected location or facility. Expansion of our existing operations is also predicated on securing the necessary environmental or land use permits and other approvals, which we may not receive in a timely manner or at all.

The enactment of derivatives legislation could impede our ability to manage business and financial risks by restricting our use of derivative instruments as hedges against fluctuating commodity prices.

On July 21, 2010 new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Dodd-Frank Act"), was enacted that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, that participate in that market. The Dodd-Frank Act requires the CFTC, the SEC and other regulators to promulgate rules and regulations implementing the Dodd-Frank Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished.

In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for, or linked to, certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time.

The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and exchange trading. To the extent we engage in such transactions or transactions that become subject to such rules in the future, we will be required to comply or to take steps to qualify for an exemption to such requirements. In addition, the Dodd-Frank Act requires that regulators establish margin rules for uncleared swaps. Although we expect to qualify for the end-user exceptions to the mandatory clearing and margin requirements for swaps entered to hedge our commercial risks, the application of the requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging.

The Dodd-Frank Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

Additionally, the Dodd-Frank Act was intended, in part, to reduce the volatility of oil and natural gas prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Dodd-Frank Act and regulations is to lower commodity prices.

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The full impact of the Dodd-Frank Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Dodd-Frank Act and any new regulations could significantly increase the cost of derivative contracts (including from swap recordkeeping and reporting requirements, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, and reduce our ability to monetize or restructure our existing derivative contracts. If we reduce our use of derivatives as a result of the Dodd-Frank Act and regulations, our results of operations may become more volatile and our cash flows may be less predictable, which could adversely affect our ability to plan for and fund capital expenditures. Any of these consequences could have a material adverse effect on our financial condition and results of operations.

In addition, the European Union and other non-U.S. jurisdictions are implementing regulations with respect to the derivatives market. To the extent we transact with counterparties in foreign jurisdictions, we may become subject to such regulations. At this time, the impact of such regulations is not clear.

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USE OF PROCEEDS

The exchange offer is intended to satisfy our obligations under the registration rights agreement. We will not receive any cash proceeds from the issuance of the new notes in the exchange offer. In consideration for issuing the new notes as contemplated by this prospectus, we will receive old notes in a like principal amount. The form and terms of the new notes are substantially identical to the form and terms of the old notes, except the new notes do not include certain transfer restrictions, registration rights or provisions for additional interest. Old notes surrendered in exchange for the new notes will be retired and cancelled and will not be reissued. Accordingly, the issuance of the new notes will not result in any change to our outstanding indebtedness.

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SELECTED FINANCIAL DATA

The following table sets forth selected financial data of the Company and its consolidated subsidiary over the five-year period ended December 31, 2014, which information has been derived from the Company's audited financial statements. This information should be read in conjunction with, and is qualified in its entirety by, the more detailed information in the Company's financial statements set forth herein.

	As of and for the Six Months Ended June 30,		As of and for the Year Ended December 31,				
	2015	2014	2014(1)	2013(2)	2012(3)	2011	2010
	(in thousands, except per share amounts)						
Income Statement Data							
Total revenues	$ 185,928	$ 292,652	$ 794,183	$ 469,506	$ 247,673	$ 209,433	$ 63,052
Net income (loss)	(791,989)	(85,743)	116,929	(343,985)	(150,097)	16,657	(15,635)
Net income (loss) attributable to common shareholders(4)	(792,789)	(93,169)	67,271	(359,574)	(156,597)	16,657	(15,635)
Net income (loss) per share attributable to common shareholders							
Basic and diluted(5)(6)	$ (117.45)	$ (14.07)	$ 10.13	$ (54.70)	$ (26.11)	N/A	N/A
Balance Sheet Data							
Cash and cash equivalents	$ 151,037	$ 29,660	$ 11,557	$ 33,163	$ 18,878	$ 7,344	$ 11,917
Net property and equipment	1,454,236	2,002,558	2,123,116	2,094,894	1,567,408	574,079	397,126
Total assets	1,796,238	2,243,284	2,475,793	2,342,107	1,684,010	624,656	427,004
Long-term debt	1,924,412	1,654,150	1,735,150	1,701,150	694,000	234,800	89,600
Stockholders'/members' equity (deficit)	(322,797)	257,583	465,862	339,999	677,469	285,502	255,879
Weighted average number of common shares outstanding(6)	6,750	6,622	6,644	6,576	5,997	N/A	N/A
Other Financial Data							
Net cash provided by operating activities(7)	$ 138,650	$ 173,561	$ 351,544	$ 237,588	$ 145,019	$ 141,550	$ 50,768
Net cash used in investing activities(7)	(149,994)	(128,028)	(404,264)	(1,204,332)	(781,378)	(242,619)	(139,618)
Net cash provided by financing activities	150,824	(49,036)	31,114	981,029	647,893	96,496	96,414
Adjusted EBITDA(8)			474,098	330,759	144,619	152,616	53,274

(1) The year ended December 31, 2014 reflects the Pine Prairie sale, which closed on May 1, 2014. For a discussion of significant divestitures, see Note 7 Acquisitions and Divestitures of Oil and Gas Properties in the Notes to the Audited Consolidated Financial Statements included in this prospectus.

(2) The year ended December 31, 2013 reflects the Anadarko Basin Acquisition, which closed on May 31, 2013. For a discussion of significant, see Note 7 Acquisitions and Divestitures of Oil and Gas Properties in the Notes to the Audited Consolidated Financial Statements included in this prospectus.

(3) The year ended December 31, 2012 reflects the Eagle Property Acquisition, which closed on October 1, 2012. For a discussion of significant acquisitions, see Note 7 Acquisitions and Divestitures of Oil and Gas Properties in the Notes to the Audited Consolidated Financial Statements included in this prospectus.

(4) The years ended December 31, 2014, 2013 and 2012 includes the effect of an undeclared Series A Preferred Stock dividend of \$10.4 million, \$15.6 million and \$6.5 million, which is, at the Company's option, to be paid in cash or in shares upon conversion. See Note 10 Preferred Stock in the Notes to the Audited Consolidated Financial Statements included in this prospectus.

(5) The net loss per share attributable to common shareholders for the year ended December 31, 2012 is on a pro forma basis, as our common stock did not trade for the entirety of 2012 (trading began on the NYSE on April 20, 2012).

(6) On August 3, 2015, the Company completed a 1-for-10 reverse stock split of its outstanding common stock. Net income (loss) per share attributable to common shareholders and the weighted average number of

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common shares outstanding have been adjusted retrospectively to reflect the reverse stock split for all periods presented.

(7) In the first quarter of 2015, the Company determined it had incorrectly presented non-cash accrued capital expenditures in its Consolidated Statements of Cash Flows since December 31, 2012. The Company corrected the cash flow presentation and reported restated amounts within Item 5. *Other Information* in its Quarterly Report on Form 10-Q for the interim period ended March 31, 2015. During the second quarter of 2015, the Company determined the restated amounts for the years ended December 31, 2013 and 2012 included in Item 5. *Other Information* of its Quarterly Report on Form 10-Q for the interim period ended March 31, 2015 required revision. As such, the Company revised the restated amounts within Item 5. *Other Information* in its Quarterly Report on Form 10-Q for the interim period ended June 30, 2015. Net cash provided by operating activities and net cash used in investing activities, as presented above, have been restated to reflect the aforementioned revisions.

(8) Adjusted EBITDA is a non GAAP financial measure. For a definition of Adjusted EBITDA and a reconciliation of Adjusted EBITDA to our net income (loss) and net cash provided by operating activities, see "Non GAAP Financial Measures and Reconciliations" below.

Non-GAAP Financial Measures and Reconciliations

Adjusted EBITDA is a supplemental non-GAAP financial measure that is used by management and external users of our consolidated financial statements, such as industry analysts, investors, lenders and rating agencies.

The Company defines Adjusted EBITDA as earnings before interest income and expense, income taxes, depreciation, depletion and amortization, property impairments, asset retirement obligation accretion, unrealized derivative gains and losses and non-cash share-based compensation expense. Adjusted EBITDA is not a measure of net income or cash flows as determined by United States generally accepted accounting principles, or GAAP. The Company believes Adjusted EBITDA is useful because it allows it to more effectively evaluate our operating performance and compare the results of our operations from period to period without regard to its financing methods or capital structure. The Company excludes items such as property and inventory impairments, asset retirement obligation accretion, unrealized derivative gains and losses and non-cash share-based compensation expense, net of amounts capitalized, from net income in arriving at Adjusted EBITDA because these amounts can vary substantially from company to company within its industry depending upon accounting methods and book values of assets, capital structures and the method by which the assets were acquired. Adjusted EBITDA should not be considered as an alternative to, or more meaningful than, net income or cash flows from operating activities as determined in accordance with GAAP or as an indicator of the Company's operating performance or liquidity. Certain items excluded from Adjusted EBITDA are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic costs of depreciable assets, none of which are components of Adjusted EBITDA. The Company's computations of Adjusted EBITDA may not be comparable to other similarly titled measures of other companies. The Company believes Adjusted EBITDA is a widely followed measure of operating performance and may also be used by investors to measure its ability to meet debt service requirements.

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The following table presents a reconciliation of the non-GAAP financial measure of Adjusted EBITDA to the GAAP measure of net income (loss) and net cash provided by operating activities, respectively.

	As of and for the Year Ended December 31,				
	2014	2013	2012	2011	2010
	(in thousands)				
Adjusted EBITDA reconciliation to net cash provided by operating activities:					
Net cash provided by operating activities(1)	$ 351,544	$ 237,588	$ 145,019	$ 141,550	$ 50,768
Changes in working capital(1)(2)	(7,098)	16,021	(11,624)	9,845	2,829
Interest income	(39)	(33)	(245)	(23)	(9)
Interest expense, net of amounts capitalized and accrued but not paid	137,548	83,138	12,999	2,094	
Amortization of deferred financing costs	(7,857)	(5,955)	(1,530)	(850)	(314)
Adjusted EBITDA	**$ 474,098**	**$ 330,759**	**$ 144,619**	**$ 152,616**	**$ 53,274**
Acquisition and transaction costs	4,129	11,803	14,884		
Adjusted EBITDA, before acquisition and transaction costs	**$ 478,227**	**$ 342,562**	**$ 159,503**	**$ 152,616**	**$ 53,274**
Adjusted EBITDA reconciliation to net income (loss):					
Net income (loss)	$ 116,929	$ (343,985)	$ (150,097)	$ 16,657	$ (15,635)
Depreciation, depletion and amortization	269,935	250,396	125,561	91,699	41,827
Impairment in carrying value of oil and gas properties	86,471	453,310			
Loss on sale/impairment of field equipment inventory	4,056	615			
(Gains) Losses on commodity derivative contracts net	(139,189)	44,284	11,158	4,844	26,268
Net cash paid for commodity derivative contracts not designated as hedging instruments	(18,332)	(17,585)	(15,825)	(16,733)	(870)
Income tax expense (benefit)	6,395	(146,529)	157,886		
Interest income	(39)	(33)	(245)	(23)	(9)
Interest expense, net of amounts capitalized	137,548	83,138	12,999	2,094	
Asset retirement obligation accretion	1,706	1,435	723	334	175
Share-based compensation, net of amounts capitalized	8,618	5,713	2,459	53,744	1,518
Adjusted EBITDA	**$ 474,098**	**$ 330,759**	**$ 144,619**	**$ 152,616**	**$ 53,274**

(1) In the first quarter of 2015, the Company determined it had incorrectly presented non-cash accrued capital expenditures in its Consolidated Statements of Cash Flows since December 31, 2012. The Company corrected the cash flow presentation and reported restated amounts within Item 5. *Other Information* in its Quarterly Report on Form 10-Q for the interim period ended March 31, 2015. During the second quarter of 2015, the Company determined the restated amounts for the years ended December 31, 2013 and 2012 included in Item 5. *Other Information* of its Quarterly Report on Form 10-Q for the interim period ended March 31, 2015 required revision. As such, the Company revised the restated amounts within Item 5. *Other Information* in its Quarterly Report on Form 10-Q for the interim period ended June 30, 2015. Net cash provided by operating activities and changes in working capital, as presented above, have been restated to reflect the aforementioned revisions.

(2) Changes in working capital for all periods have been adjusted for the loss on sale/impairment of field equipment inventory and current taxes.

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MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The following discussion and analysis of our financial condition and results of operations should be read in conjunction with our audited consolidated financial statements and notes thereto for the year ended December 31, 2014 and the unaudited condensed consolidated financial statements and notes thereto included in this prospectus.

Overview

We are an independent exploration and production company focused on the application of modern drilling and completion techniques to oil-prone resources. Our operations originally focused on the Upper Gulf Coast Tertiary trend onshore in Louisiana, which we refer to as our "Gulf Coast" operating area. We began operations in the Mississippian Lime trend in Oklahoma and Kansas with the October 1, 2012 closing of our acquisition ("Eagle Property Acquisition") of interests in producing oil and natural gas assets and unevaluated leasehold acreage in Oklahoma and Kansas and related hedging instruments from Eagle Energy Production, LLC ("Eagle Energy"). On May 31, 2013, the Company closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618.0 million in cash (the "Anadarko Basin Acquisition"), before customary post-closing adjustments. Subsequent to the closing of the Eagle Property Acquisition and the Anadarko Basin Acquisition, the Company has oil and gas operations and properties in Louisiana, Oklahoma and Texas.

Our financial results depend upon many factors, but are largely driven by the volume of our oil and natural gas production and the price that we receive for that production. The amount we realize for our production depends predominantly upon commodity prices and our related commodity price hedging activities, which are affected by changes in market demand and supply, as impacted by overall economic activity, weather, pipeline capacity, constraints, inventory storage levels, basis differentials, and other factors. Accordingly, finding and developing oil and natural gas reserves at economical costs is critical to our long-term success.

Recent Developments

Debt Restructuring

On May 21, 2015, we conducted a debt restructuring transaction which included the issuance of $625.0 million of 10.0% Senior Secured Second Lien Notes due 2020 and the use of the proceeds to repay the outstanding balance of our reserve based revolving credit facility in an amount of approximately $468.2 million, with the remainder to be utilized for general corporate purposes. Further, we exchanged approximately $504.121 million of 12.0% Third Lien Senior Secured Notes due 2020 for approximately $279.8 million of 10.75% Senior Notes due 2020 and $350.3 million of 9.25% Senior Notes due 2021, representing an exchange at 80.0% of the exchanged Senior Unsecured Notes' par value. Additionally, on June 2, 2015, we exchanged approximately $20.0 million of Third Lien Notes for approximately $26.6 million of 2020 Senior Notes and $2.0 million of 2021 Senior Notes, representing an exchange at 70.0% of the exchanged Senior Unsecured Notes' par value. Approximately $63.9 million of the principal amount of 2020 Senior Notes and $70.7 million of the principal amount of 2021 Senior Notes were extinguished as a result of the exchanges occurring at a percentage of the Senior Unsecured Notes' par value.

Additionally, we entered into the Seventh Amendment which provided that upon completion of the offering of the Second Lien Notes and Third Lien Notes, the borrowing base of the credit facility would be reduced to $252.4 million. The Seventh Amendment also provided additional covenant flexibility. Further discussion regarding the Second Lien Notes, Third Lien Notes and Seventh Amendment can be found below under " Liquidity and Capital Resources."

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Reverse Stock Split

On August 3, 2015, we completed a 1-for-10 reverse stock split of our outstanding common stock. To effect the reverse stock split, we filed a Certificate of Amendment to our Restated Certificate of Incorporation, which provides for the reverse stock split and for the corresponding reduction in our authorized capital stock to 100 million shares of common stock, $0.01 par value per share, following the reverse stock split. The consolidated financial statements and notes to the consolidated financial statements included in this document give retrospective effect to the reverse stock split for all periods presented.

Dequincy Divestiture

On April 21, 2015, we closed on the sale of ownership interest in developed and undeveloped acreage in the Dequincy area located in Beauregard and Calcasieu Parishes, Louisiana for $44.0 million to Pintail Oil and Gas LLC. The net proceeds of approximately $42.4 million, which is net of customary closing adjustments, was reflected as a reduction of oil and natural gas properties, with no gain or loss recognized. The proceeds from the sale will be used for general corporate purposes. With the Dequincy Divestiture, we no longer have any proved reserves or production in our Gulf Coast operating area.

Risks, Uncertainties and Going Concern

As a result of substantial declines in oil, natural gas liquids and natural gas prices during the latter half of 2014 and continuing into 2015, the liquidity outlook of the Company has been impacted. Decreases in commodity prices directly impact our revenues and associated operating cash flows and consequently our ability to fund our capital program and service our debt. As a result, we expect lower operating cash flows than previously experienced and if commodity prices continue to remain low, our liquidity will be further impacted as current hedging contracts expire. During the three and six months ended June 30, 2015, we received cash payments on settled derivative contracts of $42.2 million and $94.8 million, respectively. Such cash payments will not be received in 2016 and future periods due to the expiration of our hedging contracts.

Our interest payment obligations are substantial and the uncertainty associated with our ability to meet commitments as they come due or to repay outstanding debt raises substantial doubt about our ability to continue as a going concern. We received a going concern qualification from our independent registered public accounting firm for the year ended December 31, 2014, but obtained a waiver to the credit facility waiving any default as a result of receiving such qualification. The accompanying financial statements do not include any adjustments that might result from the uncertainty associated with our ability to meet obligations as they come due.

As a result of the commodity price decline and our substantial debt burden, the Company took steps to increase its liquidity and amend certain debt covenants. As discussed above, we completed the Dequincy Divestiture on April 21, 2015, for approximately $42.4 million, net of post-closing adjustments. Additionally, on May 21, 2015, we issued $625.0 million of Second Lien Notes and on May 21, 2015 and June 2, 2015 we exchanged an aggregate of approximately $524.121 million of Third Lien Notes for an aggregate of approximately $306.4 million of 2020 Senior Notes and $352.3 million of 2021 Senior Notes. Approximately $63.9 million of 2020 Senior Notes and $70.7 million of 2021 Senior Notes were extinguished as a result of the exchanges occurring at a percentage of the Senior Unsecured Notes' par value. For additional detail, please see " Liquidity and Capital Resources" below.

We also entered into the Seventh Amendment which provided that upon completion of the Second Lien Notes offering and Third Lien Notes exchange, the borrowing base of the credit facility would be reduced to $252.4 million. The Seventh Amendment also provided additional covenant flexibility. Further discussion regarding the Second Lien Notes, Third Lien Notes and Seventh Amendment can be

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found in Note 10 Long-Term Debt in the Notes to the Unaudited Consolidated Financial Statements included in this prospectus. Additionally, further discussion on liquidity can be found below under " Liquidity and Capital Resources."

Operations Update

Mississippian Lime

For the three months ended June 30, 2015 and March 31, 2015, our average daily production from the Mississippian Lime area was as follows:

	Three Months Ended June 30, 2015	Three Months Ended March 31, 2015	Increase (Decrease) in Production
Average daily production:			
Oil (Bbls)	10,828	10,675	1.4%
Natural gas liquids (Bbls)	5,314	5,367	(1.0)%
Natural gas (Mcf)	65,324	62,933	3.8%
Net boe/day	27,029	26,531	1.9%

The following table shows our total number of horizontal wells spud and brought into production in the Mississippian Lime area during the second quarter of 2015:

	Total Number of Gross Horizontal Wells Spud(1)	Total Number of Gross Horizontal Wells Brought into Production
Mississippian Lime	17	19

(1) We had four rigs drilling in the Mississippian Lime horizontal well program at June 30, 2015. Of the 17 wells spud, six were producing, seven were awaiting completion and four were being drilled at quarter-end.

In the second quarter of 2015, we invested approximately $67.7 million on completions and drilling new wells.

Anadarko Basin

For the three months ended June 30, 2015 and March 31, 2015, our average daily production from our Anadarko Basin area was as follows:

	Three Months Ended June 30, 2015	Three Months Ended March 31, 2015	Increase (Decrease) in Production
Average daily production:			
Oil (Bbls)	2,937	3,028	(3.0)%
Natural gas liquids (Bbls)	1,404	1,240	13.2%
Natural gas (Mcf)	13,468	12,734	5.8%
Net boe/day	6,586	6,390	3.1%

We did not spud any wells in the Anadarko Basin area and did not have any operated drilling rigs in the area during the second quarter of 2015.

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Gulf Coast

For the three months ended June 30, 2015 and March 31, 2015, our average daily production from the Gulf Coast area was as follows:

	Three Months Ended June 30, 2015	Three Months Ended March 31, 2015	Decrease in Production
Average daily production:			
Oil (Bbls)	194	858	(77.4)%
Natural gas liquids (Bbls)	55	274	(79.9)%
Natural gas (Mcf)	177	664	(73.3)%
Net boe/day	278	1,243	(77.6)%

Overall production decreased by 77.6% versus the first quarter of 2015 as a result of the Dequincy Divestiture, which occurred on April 21, 2015. The Dequincy Divestiture represented all of our remaining production and proved reserves in the Gulf Coast region.

No wells were spud or brought into production in our Gulf Coast area of operation during the second quarter of 2015.

Capital Expenditures

During the three and six months ended June 30, 2015, we incurred operational capital expenditures of $70.4 million and $163.3 million, respectively, which consisted primarily of:

	For the Three Months Ended June 30, 2015	For the Six Months Ended June 30, 2015
	(in thousands)	
Drilling and completion activities	$ 69,348	$ 160,399
Acquisition of acreage and seismic data	1,005	2,929
Operational capital expenditures incurred	**$ 70,353**	**$ 163,328**
Capitalized G&A, Office, ARO,& Other	2,576	4,336
Capitalized interest	1,082	2,066
Total capital expenditures incurred	**$ 74,011**	**$ 169,730**

Operational capital expenditures were incurred in the following areas:

	For the Three Months Ended June 30, 2015	For the Six Months Ended June 30, 2015
	(in thousands)	
Mississippian Lime	$ 67,700	$ 156,589
Anadarko Basin	1,493	4,656
Gulf Coast	1,160	2,083
Total capital expenditures incurred	**$ 70,353**	**$ 163,328**

We expect to invest between $250.0 million to $275.0 million of capital for exploration, development and lease and seismic acquisition during the year ended December 31, 2015.

Factors that Significantly Affect our Results

Our revenue, profitability and future growth rate depend substantially on factors beyond our control, such as economic, political and regulatory developments, as well as competition from other sources of energy. Oil and natural gas prices historically have been volatile and may fluctuate widely in the future. Sustained periods of low prices for oil or natural gas could materially and adversely affect our financial position, our results of operations, our cash flows, the quantities of oil and natural gas reserves that we can economically produce and our access to capital.

We generally hedge a portion of our expected future oil and gas production to reduce our exposure to fluctuations in commodity price. By removing a portion of commodity price volatility, we expect to reduce some of the variability in our cash flow from operations. See " Quantitative and Qualitative Disclosures About Market Risk Commodity Price Exposure" below for discussion of our hedging and hedge positions. We plan to continue our strategy of hedging the risks associated with commodity price volatility; however, given the current low commodity price environment, we may limit the extent of our hedging program in the near-term as appropriate.

Like all businesses engaged in the exploration and production of oil and natural gas, we face the challenge of natural production declines. As initial reservoir pressures are depleted, oil and natural gas production from any given well is expected to decline. As a result, oil and natural gas exploration and production companies deplete their asset base with each unit of oil or natural gas they produce. We attempt to overcome this natural production decline by developing additional reserves through our drilling operations, acquiring additional reserves and production and implementing secondary recovery techniques. Our future growth will depend on our ability to enhance production levels from our existing reserves and to continue to add reserves in excess of production. We will maintain our focus on the capital investments necessary to produce our reserves as well as to add to our reserves through drilling and acquisition. Our ability to make the necessary capital expenditures is dependent on cash flow from operations as well as our ability to obtain additional debt and equity financing. That ability can be limited by many factors, including the cost and terms of such capital and operational considerations.

The volumes of oil and natural gas that we produce are driven by several factors, including:

- success in the drilling of new wells, including exploratory wells, and the recompletion of existing wells;
- the amount of capital we invest in the leasing and development of our oil and natural gas properties;
- facility or equipment availability and unexpected downtime;
- delays imposed by or resulting from compliance with regulatory requirements; and
- the rate at which production volumes on our wells naturally decline.

We follow the full cost method of accounting for our oil and gas properties. In the first quarter and second quarter of 2015, the results of our full cost "ceiling test" required us to recognize an impairment of our oil and gas properties. While these impairments did not impact cash flow from operating activities, they did reduce our earnings and shareholders' equity. We may be required to recognize additional impairments of oil and gas properties in future periods if we experience an extended period of low commodity prices, a downward adjustment to our estimated proved reserves or the present value of estimated future net revenues, or incur actual development costs in excess of those estimates utilized in preparing our reserve reports. Additionally, the expiration of unevaluated acreage leaseholds may increase the probability of future impairments, as the costs associated with the expiring leases would be immediately included in the full cost pool and become subject to the ceiling test limitation without any corresponding increase in reserves or future net revenues.

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Results of Operations Three and Six Months Ended June 30, 2015 Compared to Three and Six Months Ended June 30, 2014

The following tables summarize our revenue, production and price data for the periods indicated.

Revenues

	For the Three Months Ended June 30,				For the Six Months Ended June 30,			
	2015		2014		2015		2014	
	(in thousands)				(in thousands)			
REVENUES:								
Oil sales	$ 67,498	72%	$ 131,273	73%	$ 126,755	69%	$ 247,495	71%
Natural gas liquid sales	10,239	11%	23,020	13%	21,249	12%	48,539	14%
Natural gas sales	15,995	17%	24,994	14%	35,167	19%	50,379	15%
Total oil, natural gas liquids, and natural gas sales	**93,732**	**100%**	**179,287**	**100%**	**183,171**	**100%**	**346,413**	**100%**
Realized gain/(losses) on commodity derivative contracts, net	42,189	(219)%	(17,138)	54%	94,797	4,560%	(31,948)	59%
Unrealized gains/(losses) on commodity derivative contracts, net	(61,482)	319%	(14,329)	46%	(92,718)	(4,460)%	(22,192)	41%
Gains (losses) on commodity derivative contracts net	**(19,293)**	**100%**	**(31,467)**	**100%**	**2,079**	**100%**	**(54,140)**	**100%**
Other	315		170		678		379	
Total revenues	**$ 74,754**		**$ 147,990**		**$ 185,928**		**$ 292,652**	

Production

	For the Three Months Ended June 30			For the Six Months Ended June 30		
	2015	2014	% Change	2015	2014	% Change
PRODUCTION DATA:						
Oil (MBbls)	1,270	1,300	(2)%	2,581	2,508	3%
Natural gas liquids (MBbls)	616	601	3%	1,236	1,134	9%
Natural gas (MMcf)	7,186	6,013	20%	14,056	11,237	25%
Oil equivalents (MBoe)	3,084	2,904	6%	6,160	5,514	12%
Oil (Bbls/day)	13,959	14,290	(2)%	14,258	13,856	3%
Natural gas liquids (Bbls/day)	6,773	6,609	2%	6,827	6,263	9%
Natural gas (Mcf/day)	78,969	66,078	20%	77,657	62,085	25%
Average daily production (Boe/day)	33,893	31,912	6%	34,028	30,466	12%

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Prices

	For the Three Months Ended June 30			For the Six Months Ended June 30		
	2015	2014	% Change	2015	2014	% Change
AVERAGE SALES PRICES:						
Oil, without realized derivatives (per Bbl)	$ 53.14	$ 100.95	(47)%	$ 49.12	$ 98.69	(50)%
Oil, with realized derivatives (per Bbl)	$ 81.19	$ 89.12	(9)%	$ 80.30	$ 88.13	(9)%
Natural gas liquids, without realized derivatives (per Bbl)	$ 16.61	$ 38.27	(57)%	$ 17.20	$ 42.82	(60)%
Natural gas liquids, with realized derivatives (per Bbl)	$ 16.61	$ 38.52	(57)%	$ 17.20	$ 42.88	(60)%
Natural gas, without realized derivatives (per Mcf)	$ 2.23	$ 4.16	(46)%	$ 2.50	$ 4.48	(44)%
Natural gas, with realized derivatives (per Mcf)	$ 3.14	$ 3.84	(18)%	$ 3.52	$ 3.99	(12)%

Three Months Ended June 30, 2015 as Compared to the Three Months Ended June 30, 2014

Oil, natural gas liquids and natural gas sales revenues

Our oil, NGL and natural gas sales revenues decreased by $85.6 million, or 47.7%, to $93.7 million during the three months ended June 30, 2015, as compared to $179.3 million during the three months ended June 30, 2014. The major contributing factor to this decrease was the substantially lower commodity prices for the three months ended June 30, 2015 as compared to the three months ended June 30, 2014.

Our oil sales revenues decreased by $63.8 million, or 48.6%, to $67.5 million during the three months ended June 30, 2015, as compared to $131.3 million for the three months ended June 30, 2014. Oil volumes sold decreased 331 Bbls/d, or 2.3%, to 13,959 Bbls/d for the three months ended June 30, 2015, from 14,290 Bbls/d for the three months ended June 30, 2014. The decrease in oil volumes sold was primarily attributable to lower production in our Gulf Coast area due to the Dequincy Divestiture, which impacted sales by 1,494 Bbls/d, as well as lower production from our Anadarko Basin area of 1,443 Bbls/d attributable to a decrease in drilling activity. These decreases were largely offset by increased production in the Mississippian Lime area of 2,606 Bbls/d.

Our NGL sales revenues decreased by $12.8 million, or 55.5%, to $10.2 million during the three months ended June 30, 2015, as compared to $23.0 million for the three months ended June 30, 2014. NGL volumes sold increased 164 Bbls/day, or 2.5%, to 6,773 Bbls/d for the three months ended June 30, 2015, from 6,609 Bbls/d for the three months ended June 30, 2014. This increase in NGL volumes sold was attributable to the increased production in the Mississippian Lime area of 869 Bbls/d partially offset by a 329 Bbls/d decrease in production from our Gulf Coast area due to the Dequincy Divestiture and reduced development drilling activity in our Anadarko Basin area, which resulted in lower NGL production of 376 Bbls/d.

Our natural gas sales revenues decreased by $9.0 million, or 36.0%, to $16.0 million during the three months ended June 30, 2015, as compared to $25.0 million for the three months ended June 30, 2014. Natural gas volumes sold increased 12,891 Mcf/d or 19.5%, to 78,969 Mcf/day for the three months ended June 30, 2015, from 66,078 Mcf/d for the three months ended June 30, 2014. The increase in natural gas volumes sold was attributable to increased production of 17,138 Mcf/d in the Mississippian Lime area due to the development drilling program and, starting in October 2014, ethane rejection on the gas processing side, partially offset by a decrease in production of 1,367 Mcf/d from our Gulf Coast area due to the Dequincy Divestiture and reduced development drilling activity in our Anadarko Basin area, which resulted in lower natural gas production of 2,880 Mcf/d.

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Gains/losses on commodity derivative contracts net

Our mark-to-market ("MTM") derivative positions moved from an unrealized loss of $14.3 million for the three months ended June 30, 2014 to an unrealized loss of $61.5 million for the three months ended June 30, 2015. The NYMEX WTI closing price on June 30, 2015 was $59.47 per barrel compared to a closing price of $105.37 per barrel on June 30, 2014.

Our realized gain on derivatives for the three months ended June 30, 2015 was $42.2 million, compared to a realized loss of $17.1 million for the three months ended June 30, 2014. The following table presents realized gain by type of commodity contract for the three months ended June 30, 2015:

	For the Three Months Ended June 30, 2015	
	Realized Gain	**Average Sales Price**
	(in thousands)	
Oil commodity contracts	$ 35,627	$ 81.19
Natural gas commodity contracts	6,562	3.14
Realized gains on commodity derivative contracts, net	**$ 42,189**	

Cash settlements, as presented in the table above, represent realized gains related to our derivative instruments. In addition to cash settlements, we also recognize fair value changes on our derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves.

Six Months Ended June 30, 2015 as Compared to the Six Months Ended June 30, 2014

Oil, natural gas liquids and natural gas sales revenues

Our oil, NGL and natural gas sales revenues decreased by $163.2 million, or 47.1%, to $183.2 million during the six months ended June 30, 2015, as compared to $346.4 million during the six months ended June 30, 2014. The major contributing factor to this decrease was the substantially lower commodity prices for the six months ended June 30, 2015 as compared to the six months ended June 30, 2014.

Our oil sales revenues decreased by $120.7 million, or 48.8%, to $126.8 million during the six months ended June 30, 2015, as compared to $247.5 million for the six months ended June 30, 2014. Oil volumes sold increased 402 Bbs/d, or 2.9%, to 14,258 Bbls/d for the six months ended June 30, 2015, from 13,856 Bbls/day for the six months ended June 30, 2014. This increase in oil volumes sold was attributable to increased production period over period in the Mississippian Lime area of 3,595 Bbls/d, partially offset by lower production in our Gulf Coast area due to the Dequincy Divestiture, which impacted sales by 1,813 Bbls/d, as well as lower production from our Anadarko Basin area of 1,380 Bbls/d, attributable to a decrease in drilling activity during the period and base production declines.

Our NGL sales revenues decreased by $27.3 million, or 56.2%, to $21.3 million during the six months ended June 30, 2015, as compared to $48.5 million for the six months ended June 30, 2014. NGL volumes sold increased 564 Bbls/d, or 9.0%, to 6,827 Bbls/d for the six months ended June 30, 2015, from 6,263 Bbls/d for the six months ended June 30, 2014. This increase in NGL volumes was attributable to the increased production in the Mississippian Lime area of 1,367 Bbls/d. Increased production in our Mississippian Lime area was offset by a 388 Bbls/d decrease in production from our Gulf Coast area due to the Dequincy Divestiture and reduced development drilling activity in the Anadarko Basin, which contributed to a decrease of 415 Bbls/d.

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Our natural gas sales revenues decreased by $15.2 million, or 30.2%, to $35.2 million during the six months ended June 30, 2015, as compared to $50.4 million for the six months ended June 30, 2014. Natural gas volumes sold increased 15,572 Mcf/d or 25.1%, to 77,657 Mcf/d for the six months ended June 30, 2015, from 62,085 Mcf/d for the six months ended June 30, 2014. This increase in natural gas volumes sold was attributable to increased production of 19,614 Mcf/day in the Mississippian Lime area, partially offset by a decrease in production of 1,944 Mcf/d from our Gulf Coast area due to the Dequincy Divestiture and reduced development drilling activity in the Anadarko Basin, which contributed a decrease of 2,098 Mcf/d.

Gains/losses on commodity derivative contracts net

Our MTM derivative positions moved from an unrealized loss of $22.2 million for the six months ended June 30, 2014 to an unrealized loss of $92.7 million for the six months ended June 30, 2015. The NYMEX WTI closing price on June 30, 2015 was $59.47 per barrel compared to a closing price of $105.37 per barrel on June 30, 2014.

The realized gain on derivatives for the six months ended June 30, 2015 was $94.8 million compared to a realized loss of $32.0 million for the six months ended June 30, 2014. The following table presents realized gain by type of commodity contract for the six months ended June 30, 2015:

	For the Six Months Ended June 30, 2015	
	Realized Gain	**Average Sales Price**
	(in thousands)	
Oil commodity contracts	$ 80,484	$ 80.30
Natural gas commodity contracts	14,313	3.52
Realized gains on commodity derivative contracts, net	**$ 94,797**	

Cash settlements, as presented in the table above, represent realized gains related to our derivative instruments. In addition to cash settlements, we also recognize fair value changes on our derivative instruments in each reporting period. The changes in fair value result from new positions and settlements that may occur during each reporting period, as well as the relationships between contract prices and the associated forward curves.

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Operating Expenses

The table below presents a comparison of our expenses on an absolute dollar basis and a per Boe basis. Depending on the relevance, our discussion may reference expenses on an absolute dollar basis, a per Boe basis, or both.

	Three Months Ended June 30,				Six Months Ended June 30,			
	2015	**2014**	**2015**	**2014**	**2015**	**2014**	**2015**	**2014**
	(in thousands)		**(per Boe)**		**(in thousands)**		**(per Boe)**	
EXPENSES:								
Lease operating and workover	$ 21,758	$ 19,721	$ 7.06	$ 6.79	$ 45,020	$ 39,848	$ 7.31	$ 7.23
Gathering and transportation	3,931	2,940	1.27	1.01	7,369	5,795	1.20	1.05
Severance and other taxes	2,505	5,632	0.81	1.94	6,069	13,279	0.99	2.41
Asset retirement accretion	390	432	0.13	0.15	835	929	0.14	0.17
Depreciation, depletion, and amortization	55,255	71,074	17.92	24.47	113,683	137,975	18.46	25.02
Impairment of oil and gas properties	498,389		161.60		673,056	86,471	109.28	15.68
General and administrative	11,461	13,434	3.71	4.63	23,115	25,118	3.75	4.56
Acquisition and transaction costs	251	2,483	0.09	0.86	251	2,611	0.04	0.47
Debt restructuring costs	34,398		11.15		36,141		5.87	
Other		609		0.21	73	939	0.01	0.17
Total expenses	**$ 628,338**	**$ 116,325**	**$ 203.74**	**$ 40.06**	**$ 905,612**	**$ 312,965**	**$ 147.05**	**$ 56.76**

Three Months Ended June 30, 2015 as Compared to the Three Months Ended June 30, 2014

Lease operating and workover expenses

Lease operating and workover expenses increased $2.0 million, or 10.3%, to $21.8 million for the three months ended June 30, 2015 compared to $19.7 million for the three months ended June 30, 2014. The increase in lease operating and workover expenses was primarily due to workover activity related to production optimization projects, higher environmental compliance costs and higher costs associated with the increase in producing well count period over period, partially offset by lower lease operating expenses due to the Dequincy Divestiture. Lease operating and workover expenses increased to $7.06 per Boe for the three months ended June 30, 2015, an increase of $0.27, or 4.0%, over the $6.79 per Boe for the three months ended June 30, 2014, primarily for the reasons noted above.

Gathering and transportation

Gathering and transportation expenses were $3.9 million for the three months ended June 30, 2015, as compared to $2.9 million for the three months ended June 30, 2014. These expenses are primarily attributable to a gas transportation, gathering and processing contract covering the Mississippian Lime area that includes a $0.36 per Mmbtu gathering fee based upon wellhead volumes. As such, the increase in our gathering and transportation costs is due to increased natural gas production in our Mississippian Lime area.

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Severance and other taxes

	Three Months Ended June 30, 2015	Three Months Ended June 30, 2014
Total oil, natural gas, and natural gas liquids sales	**$ 93,732**	**$ 179,287**
Severance taxes	1,229	4,353
Ad valorem and other taxes	1,276	1,279
Severance and other taxes	**$ 2,505**	**$ 5,632**
Severance taxes as a percentage of sales	**1.3%**	**2.4%**
Severance and other taxes as a percentage of sales	**2.7%**	**3.1%**

Severance and other taxes decreased $3.1 million, or 55.5%, to $2.5 million for the three months ended June 30, 2015 compared to $5.6 million for the three months ended June 30, 2014. Severance taxes decreased $3.1 million, or 71.8%, to $1.2 million for the three months ended June 30, 2015, as compared to $4.4 million for the three months ended June 30, 2014. Severance taxes as a percentage of sales changed from 2.4% for the three months ended June 30, 2014 to 1.3% for the corresponding 2015 period due to lower realized pricing as well as a refund received in the 2015 period for production taxes paid in prior periods of $0.6 million. Ad valorem taxes were essentially unchanged for the three months ended June 30, 2015, as compared to the three months ended June 30, 2014.

Depreciation, depletion and amortization (DD&A)

DD&A expense decreased $15.8 million, or 22.3%, to $55.3 million for the three months ended June 30, 2015 compared to $71.1 million for the three months ended June 30, 2014. The decrease in DD&A expense was driven by downward revisions in our proved undeveloped reserves in the Anadarko Basin from June 30, 2014, which decreased estimated finding and developments costs and as a result, reduced our DD&A expense, as well as the ceiling test impairments recorded during the period. Additionally, our depletion rate has decreased from approximately 2.3% for the three months ended June 30, 2014 to 2.0% for the three months ended June 30, 2015, primarily as a result of increased proved developed reserve volumes. The DD&A rate for 2015 was $17.92 per Boe, compared to $24.47 per Boe for 2014 as a result of the factors discussed above.

Impairment of oil and gas properties

We recorded pre-tax impairment expense related to our oil and natural gas properties for the three months ended June 30, 2015 of $498.4 million as a result of our full-cost ceiling test. Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of capitalized costs associated with our oil and natural gas properties in our condensed consolidated balance sheets. The impairment expense for the three months ended June 30, 2015 was due to a decrease in the PV-10 value of our proven oil and natural gas reserves as a result of low commodity prices.

General and administrative (G&A)

Our G&A expenses decreased by $2.0 million, or 14.7%, to $11.5 million for the three months ended June 30, 2015, compared to $13.5 million for the three months ended June 30, 2014. The decrease is primarily due to lower employee related costs period over period, mainly due to lower headcount and the closure of our Houston office.

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Acquisition and transaction costs

Our acquisition and transaction costs were $0.3 million for the three months ended June 30, 2015, related to the Dequincy Divestiture, compared to $2.5 million for the three months ended June 30, 2014, representing our expenses related to the Pine Prairie disposition in 2014.

Debt restructuring costs

During the 2015 period, we engaged various advisors to assist us in analyzing options to improve our financial flexibility and provide additional long-term liquidity. For the three months ended June 30, 2015, we incurred approximately $34.4 million in fees associated with these advisors as well as issuance costs associated with the Second Lien Notes offering and Third Lien Notes exchange.

Other

Other operating expenses for the three months ended June 30, 2014 were $0.6 million and represent the loss on disposal of field equipment inventory deemed no longer essential to operations. No such expenses were incurred in the three months ended June 30, 2015.

Six Months Ended June 30, 2015 as Compared to the Six Months Ended June 30, 2014

Lease operating and workover expenses

Lease operating and workover expenses increased $5.1 million, or 13.0%, to $45.0 million for the six months ended June 30, 2015 compared to $39.8 million for the six months ended June 30, 2014. The increase in lease operating and workover expenses was primarily due to costs associated with the increase in producing well count period over period and higher environmental compliance costs, partially offset by lower lease operating expenses due to the Dequincy Divestiture. Lease operating and workover expenses increased minimally to $7.31 per Boe for the six months ended June 30, 2015, an increase of $0.08, or 1.1%, from the $7.23 per Boe for the six months ended June 30, 2014, primarily for the reasons noted above.

Gathering and transportation

Gathering and transportation expenses were $7.4 million for the six months ended June 30, 2015, as compared to $5.8 million for the six months ended June 30, 2014. These expenses are primarily attributable to a gas transportation, gathering and processing contract covering the Mississippian Lime area that includes a $0.36 per Mmbtu gathering fee based upon wellhead volumes. As such, the increase in our gathering and transportation costs is due to increased natural gas production in our Mississippian Lime area.

Severance and other taxes

	Six Months Ended June 30,	
	2015	**2014**
Total oil, natural gas, and natural gas liquids sales	**$ 183,171**	**$ 346,413**
Severance taxes	3,011	10,162
Ad valorem and other taxes	3,058	3,117
Severance and other taxes	**$ 6,069**	**$ 13,279**
Severance taxes as a percentage of sales	**1.6%**	**2.9%**
Severance and other taxes as a percentage of sales	**3.3%**	**3.8%**

Severance and other taxes decreased $7.2 million, or 54.3%, to $6.1 million for the six months ended June 30, 2015, compared to $13.3 million for the six months ended June 30, 2014. Severance taxes decreased $7.2 million, or 70.4%, to $3.0 million for the six months ended June 30, 2015, as compared to $10.2 million for the six months ended June 30, 2014. Severance taxes as a percentage of sales changed from 2.9% for the six months ended June 30, 2014 to 1.6% for the corresponding 2015 period due to lower realized pricing as well as a refund received in 2015 for production taxes paid in prior periods of $0.6 million. Ad valorem taxes were essentially unchanged for the six months ended June 30, 2015, as compared to the six months ended June 30, 2014.

Depreciation, depletion and amortization

DD&A expense decreased $24.3 million, or 17.6%, to $113.7 million for the six months ended June 30, 2015 compared to $138.0 million for the six months ended June 30, 2014. The decrease in DD&A expense was driven by downward revisions in our proved undeveloped reserves in the Anadarko Basin from June 30, 2014, which decreased estimated finding and developments costs and as a result, reduced our DD&A expense, as well as the ceiling test impairments recorded during the period. Additionally, our depletion rate has decreased from an average of approximately 2.2% for the six months ended June 30, 2014 to an average of 2.0% for the six months ended June 30, 2015, primarily as a result of increased proved developed reserve volumes. The DD&A rate for 2015 was $18.46 per Boe, compared to $25.02 per Boe for 2014 as a result of the factors discussed above.

Impairment of oil and gas properties

We recorded pre-tax impairment expense related to our oil and natural gas properties for the six months ended June 30, 2015 and 2014 of $673.1 million and $86.5 million, respectively, as a result of our full-cost ceiling test. Under the full cost method, we are subject to quarterly calculations of a ceiling or limitation on the amount of capitalized costs associated with our oil and natural gas properties in our condensed consolidated balance sheets. The impairment expense for the six months ended June 30, 2015 was due to a decrease in the PV-10 value of our proven oil and natural gas reserves as a result of low commodity prices. The impairment expense for six months ended June 30, 2014 was largely due to the transfer of unevaluated property costs to the full cost pool during the first quarter of 2014. During the first quarter of 2014, we transferred $21.4 million and $38.1 million related to the Mississippian Lime and Anadarko Basin areas, respectively, as we released acreage that did not present the best near term development potential.

General and administrative

Our G&A expenses decreased by $2.0 million, or 8.0%, to $23.1 million for the six months ended June 30, 2015, compared to $25.1 million for the six months ended June 30, 2014. The decrease is primarily attributable to due to lower stock compensation and other employee related expenses due to lower headcount and the closure of the Houston office.

Acquisition and transaction costs

Our acquisition and transaction costs were $0.3 million for the six months ended June 30, 2014, related to the Dequincy Divestiture, compared to $2.6 million for the six months ended June 30, 2014, representing our expenses related to the Pine Prairie disposition in 2014.

Debt restructuring costs

During the 2015 period, we engaged various advisors to assist us in analyzing options to improve our financial flexibility and provide additional long-term liquidity. For the six months ended June 30,

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2015, we incurred approximately $36.1 million in fees associated with these advisors as well as issuance costs associated with the Second Lien Notes offering and Third Lien Notes exchange.

Other

Other operating expenses for the six months ended June 30, 2015 and 2014 were $0.1 million and $0.9 million, respectively. For 2014, these costs represent the loss on disposal of field equipment inventory deemed no longer essential to operations.

Other Income (Expense)

	For the Three Months Ended June 30,		For the Six Months Ended June 30,	
	2015	**2014**	**2015**	**2014**
	(in thousands)		(in thousands)	
OTHER INCOME (EXPENSE)				
Interest income	$ 27	$ 9	$ 36	$ 19
Interest expense	(45,962)	(37,157)	(83,448)	(75,722)
Capitalized Interest	1,082	3,344	2,066	7,962
Interest expense net of amounts capitalized	(44,880)	(33,813)	(81,382)	(67,760)
Total other expense	**$ (44,853)**	**$ (33,804)**	**$ (81,346)**	**$ (67,741)**

Interest expense

Three Months Ended June 30, 2015 as Compared to the Three Months Ended June 30, 2014

Interest expense for the three months ended June 30, 2015 and 2014 was $46.0 million and $37.2 million, respectively. The increase in interest expense was primarily due to the issuance of the Second Lien Notes and Third Lien Notes on May 21, 2015. The Second Lien Notes bear interest at 10.0% and were used to repay outstanding borrowings under the credit facility, which had an interest rate of 2.9% at June 30, 2015. Additionally, the Third Lien Notes bear interest at 12.0% and were exchanged for a portion of the 2020 Senior Notes and 2021 Senior Notes, which had stated interest rates of 10.75% and 9.25%, respectively. Further, approximately $4.6 million in unamortized debt costs were impaired during the three months ended June 30, 2015 as a result of the Seventh Amendment to the credit facility. For the three months ended June 30, 2015 and 2014, approximately $1.1 million and $3.3 million, respectively, in interest expense was capitalized to oil and gas properties. Capitalized interest was lower due to a decrease in the balance of our unevaluated property from June 30, 2014.

Six Months Ended June 30, 2015 as Compared to the Six Months Ended June 30, 2014

Interest expense for the six months ended June 30, 2015 and 2014 was $83.4 million and $75.7 million, respectively. The increase in interest expense was primarily due to the issuance of the Second Lien Notes and Third Lien Notes on May 21, 2015. The Second Lien Notes bear interest at 10.0% and were used to repay outstanding borrowings under the credit facility, which had an interest rate of 2.9% at June 30, 2015. Additionally, the Third Lien Notes bear interest at 12.0% and were exchanged for a portion of the 2020 Senior Notes and 2021 Senior Notes, which had stated interest rates of 10.75% and 9.25%, respectively. Further, approximately $4.6 million in unamortized debt costs were impaired during the six months ended June 30, 2015 as a result of the Seventh Amendment to the credit facility. For the six months ended June 30, 2015 and 2014, approximately $2.1 million and $8.0 million, respectively, in interest expense was capitalized to oil and gas properties. Capitalized interest was lower due to a decrease in the balance of our unevaluated property from June 30, 2014

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Provision for Income Taxes

Three Months Ended June 30, 2015 as Compared to the Three Months Ended June 30, 2014

We had no income tax benefit or expense for the three months ended June 30, 2015, compared to a benefit of $0.1 million for the three months ended June 30 2014. Our effective tax rate for the second quarter of 2015 differs from the federal statutory rate of 35% due to the effect of recurring permanent adjustments, state income taxes and changes in the valuation allowance We expect to incur a tax loss in the current year due to the flexibility in deducting or capitalizing current year intangible drilling costs; thus no current income taxes are anticipated to be paid.

A valuation allowance has been recorded as management does not believe that it is more-likely-than-not that its NOLs are realizable except to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

Six Months Ended June 30, 2015 as Compared to the Six Months Ended June 30, 2014

Our income tax benefit was $9.0 million and $2.3 million for the six months ended June 30, 2015 and 2014, respectively. For the six months ended June 30, 2015, our effective tax rate was a benefit of approximately 1.1%. Our effective tax rate for the six months ended June 30, 2015 differs from the federal statutory rate of 35% due to the effect of recurring permanent adjustments, state income taxes and changes in the valuation allowance.

This year, we recorded $305.9 million in additional valuation allowance in light of the impairment of oil and gas properties and the settlement of certain hedging contracts that existed at December 31, 2014, bringing the total valuation allowance to $309.7 million at June 30, 2015.

Results of Operations Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 and Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

The following tables summarize our revenue, production and price data for the periods indicated. Prior to May 1, 2014, our operating results include production, revenue and lease operating expenses attributable to our Pine Prairie field, the sale of which closed effective May 1, 2014. Where applicable, in the following discussion, we have noted normalized production, revenue, lease operating expenses and percentages for prior periods as though the Pine Prairie Disposition occurred as of the beginning of that period.

Revenues

	Years Ended December 31, (in thousands)					
	2014		**2013**		**2012**	
REVENUES:						
Oil sales	$ 466,655	71%	$ 387,226	76%	$ 218,430	85%
Natural gas liquid sales	87,771	13%	62,340	12%	23,617	9%
Natural gas sales	99,204	16%	63,187	12%	16,030	6%
Total oil, natural gas, and natural gas liquids sales	$ 653,630	100%	$ 512,753	100%	258,077	100%
Realized losses on commodity derivative contracts, net	(18,332)	(13)%	(17,585)	40%	(15,825)	142%
Unrealized gains (losses) on commodity derivative contracts, net	157,521	113%	(26,699	60%	4,667	(42)%
Gains (losses) on commodity derivative contracts net	$ 139,189	100%	$ (44,284)	100%	$ (11,158)	100%
Other	1,364		1,037		754	
Total revenues	**$ 794,183**		**$ 469,506**		**$ 247,673**	

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Production

	Years Ended December 31,				
	2014	% Change	2013	% Change	2012
PRODUCTION DATA:					
Oil (MBbls)	5,144	32%	3,904	87%	2,093
Natural gas liquids (MBbls)	2,417	41%	1,719	179%	617
Natural gas (MMcf)	25,013	34%	18,657	228%	5,695
Oil equivalents (MBoe)	11,730	34%	8,733	139%	3,659
Oil (Boe/day)	14,094	32%	10,697	87%	5,719
Natural gas liquids (Boe/day)	6,622	41%	4,711	179%	1,686
Natural gas (Mcf/day)	68,528	34%	51,116	228%	15,559
Average daily production (Boe/d)	32,137	34%	23,927	139%	9,999

Prices

	Years Ended December 31,				
	2014	% Change	2013	% Change	2012
AVERAGE SALES PRICES:					
Oil, without realized derivatives (per Bbl)	$ 90.71	(9)%	$ 99.18	(5)%	$ 104.35
Oil, with realized derivatives (per Bbl)	$ 87.40	(6)%	$ 93.41	(2)%	$ 95.05
Natural gas liquids, without realized derivatives (per Bbl)	$ 36.31	0%	$ 36.26	(5)%	$ 38.27
Natural gas liquids, with realized derivatives (per Bbl)	$ 36.40	(2)%	$ 37.09	(8)%	$ 40.48
Natural gas, without realized derivatives (per Mcf)	$ 3.97	17%	$ 3.39	21%	$ 2.81
Natural gas, with realized derivatives (per Mcf)	$ 3.91	9%	$ 3.58	12%	$ 3.21

Oil, Natural Gas and Natural Gas Liquids Revenues.

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Our oil sales revenues increased by $79.5 million, or 21%, to $466.7 million during the year ended December 31, 2014 as compared to $387.2 million for the year ended December 31, 2013. Oil volumes sold increased 1,240 MBbls or 32% to 5,144 MBbls for the year ended December 31, 2014 from 3,904 MBbls for the year ended December 31, 2013. The increase in oil volumes sold was due to an increase of 1,403 MBbls in production volumes from our Mississippian Lime area attributable to continued increased drilling activity in 2014, and 648 MBbls of additional production volumes from our Anadarko Basin area (the 2013 comparative period included only seven months of results due to the timing of the Anadarko Basin Acquisition), partially offset by a decrease in Gulf Coast production of 811 MBbls (of which, approximately 632 MBbls was related to the Pine Prairie area). For the twelve months ended December 31, 2014, we brought approximately 120 wells online, which contributed to the 34% increase in daily production. Average oil sales prices, without realized derivatives, decreased by $8.47 per barrel, or 9%, to $90.71 per barrel for the year ended December 31, 2014 as compared to $99.18 for the year ended December 31, 2013. Of the $466.7 million in total oil sales revenues, $272.9 million was from Mississippian Lime operations, $134.0 million was from the Anadarko Basin and $59.8 million was from the Gulf Coast.

Our NGLs sales revenues increased by $25.5 million, or 41%, to $87.8 million during the year ended December 31, 2014 as compared to $62.3 million for the year ended December 31, 2013. NGLs volumes sold increased 698 MBbls, or 41%, to 2,417 MBbls for the year ended December 31, 2014 as compared to 1,719 MBbls for the year ended December 31, 2013. The increase in NGLs volumes sold was attributable to an increase of 663 MBbls of production volumes from our Mississippian Lime area and

250 MBbls of additional production volumes from our Anadarko Basin area (the 2013 comparative period included only seven months of results due to the timing of the Anadarko Basin Acquisition), partially offset by a decrease in Gulf Coast production of 215 MBbls (of which, approximately 137 MBbls related to the Pine Prairie area). Average NGLs prices, without realized derivatives, increased by $0.05 per barrel, to $36.31 per barrel for the year ended December 31, 2014 as compared to $36.26 per barrel for the year ended December 31, 2013. Of the $87.8 million in total NGLs revenues, $57.7 million was from Mississippian Lime operations, $23.8 million was from the Anadarko Basin and $6.3 million was from the Gulf Coast.

Our natural gas sales revenues increased by $36.0 million, or 57%, to $99.2 million during the year ended December 31, 2014 as compared to $63.2 million for the year ended December 31, 2013. Natural gas volumes sold increased 6,356 MMcf, or 34%, to 25,013 MMcf for the year ended December 31, 2014 as compared to 18,657 MMcf for the year ended December 31, 2013. The increase in natural gas volumes sold was attributable to an increase of 6,293 MMcf of production volumes from our Mississippian Lime area and 1,960 MMcf of additional production volumes from our Anadarko Basin area (the 2013 comparative period included only seven months of results due to the timing of the Anadarko Basin Acquisition), partially offset by a 1,897 MMcf decrease in production from our Gulf Coast area (of which, approximately 1,577 MMcf related to the Pine Prairie area). Average natural gas prices, without realized derivatives, increased by $0.58 per Mcf, or 17%, to $3.97 per Mcf for the year ended December 31, 2014 as compared to $3.39 per Mcf for the year ended December 31, 2013. Of the $99.2 million in total natural gas sales revenues, $75.4 million was from Mississippian Lime operations, $21.1 million was from Anadarko Basin and $2.7 million was from the Gulf Coast.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our oil sales revenues increased by $168.8 million, or 77%, to $387.2 million during the year ended December 31, 2013 as compared to $218.4 million for the year ended December 31, 2012. Oil volumes sold increased 1,811 MBbls or 87% to 3,904 MBbls for the year ended December 31, 2013 from 2,093 MBbls for the year ended December 31, 2012. The increase in oil volumes sold was attributable to an increase of 1,463 MBbls in production volumes from our Mississippian area attributable to a full year of production from the assets (which were acquired on October 1, 2012) and the results from increased drilling activity in 2013, and the addition of 817 MBbls in production volumes from our Anadarko Basin area (which was acquired on May 31, 2013), partially offset by a decrease in Gulf Coast production of 469 MBbls. Production from the Gulf Coast declined due to lower drilling activity during the latter half of 2013 as we focused drilling capital on our newly acquired Anadarko Basin assets. Average oil sales prices, without realized derivatives, decreased by $5.17 per barrel, or 5%, to $99.18 per barrel for the year ended December 31, 2013 as compared to $104.35 for the year ended December 31, 2012, partly due to lower oil prices during 2013 as well as lower oil prices received for our Mississippian Lime and Anadarko Basin production, which is priced off WTI as opposed to LLS for our Gulf Coast production. Of the $387.2 million in total oil sales revenues, $151.7 million was from Gulf Coast operations, $155.9 million was from Mississippian and $79.6 million was from Anadarko Basin.

Our NGLs sales revenues increased by $38.7 million, or 164%, to $62.3 million during the year ended December 31, 2013 as compared to $23.6 million for the year ended December 31, 2012. NGLs volumes sold increased 1,102 MBbls, or 179%, to 1,719 MBbls for the year ended December 31, 2013 as compared to 617 MBbls for the year ended December 31, 2012. The increase in NGLs volumes sold was attributable to an increase of 789 MBbls of production volumes from our Mississippian Lime area and the addition of 395 MBbls of production volumes from our Anadarko Basin area, partially offset by a decrease in Gulf Coast production of 82 MBbls. Average NGLs prices, without realized derivatives, decreased by $2.01 per barrel, or 5%, to $36.26 per barrel for the year ended December 31, 2013 as compared to $38.27 per barrel for the year ended December 31, 2012. Of the $62.3 million in

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total NGLs revenues, $13.9 million was from Gulf Coast operations, $34.5 million was from Mississippian Lime and $13.9 million was from Anadarko Basin.

Our natural gas sales revenues increased by $47.2 million, or 295%, to $63.2 million during the year ended December 31, 2013 as compared to $16.0 million for the year ended December 31, 2012. Natural gas volumes sold increased 12,962 MMcf, or 228%, to 18,657 MMcf for the year ended December 31, 2013 as compared to 5,695 MMcf for the year ended December 31, 2012. The increase in natural gas volumes sold was attributable to an increase of 10,946 MMcf of production volumes from our Mississippian Lime area and the addition of 3,489 MMcf of production volumes from our Anadarko Basin area, partially offset by a 1,473 MMcf decrease in production from our Gulf Coast area. Average natural gas prices, without realized derivatives, increased by $0.58 per Mcf, or 21%, to $3.39 per Mcf for the year ended December 31, 2013 as compared to $2.81 per Mcf for the year ended December 31, 2012. Of the $63.2 million in total natural gas sales revenues, $9.4 million was from Gulf Coast operations, $42.6 million was from Mississippian and $11.2 million was from Anadarko Basin.

Gains/Losses on Commodity Derivative Contracts Net.

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Our MTM derivative positions moved from an unrealized loss of $26.7 million as of December 31, 2013 to an unrealized gain of $157.5 million for the year ending December 31, 2014. The NYMEX WTI closing price on December 31, 2014 was $53.27 per barrel compared to a closing price of $98.42 per barrel on December 31, 2013 and the average oil price of our open derivative contracts was $88.72 per barrel.

The realized loss on derivatives for the year ended December 31, 2014 was $18.3 million compared to a realized loss of $17.6 million for the year ended December 31, 2013. See the following table:

	Year Ended December 31, 2014	
	Realized Gain (Loss)	Average Sales Price
	(in thousands)	
Oil commodity contracts	$ (17,060)	$ 87.40
Natural gas liquids commodity contracts	217	36.40
Natural gas commodity contracts	(1,489)	3.91
Realized losses on commodity derivative contracts, net	(18,332)	

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our MTM derivative positions moved from an unrealized gain of $4.7 million as of December 31, 2012 to an unrealized loss of $26.7 million for the year ending December 31, 2013. We entered into additional derivative contracts during 2013 and the MTM change resulted from higher average hedge volumes and unfavorable derivative contract price variances versus the forward strip price for our production on December 31, 2013. The NYMEX WTI closing price on December 31, 2013 was $98.42 per barrel compared to a closing price of $91.82 per barrel on December 31, 2012.

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The realized loss on derivatives for the year ended December 31, 2013 was $17.6 million compared to a realized loss of $15.8 million for the year ended December 31, 2012. See the following table (in thousands):

	Year Ended December 31, 2013	
	Realized Gain (Loss)	Average Sales Price
	(in thousands)	
Oil commodity contracts	$ (22,529)	$ 93.41
Natural gas liquids commodity contracts	1,428	37.09
Natural gas commodity contracts	3,516	3.58
Realized losses on commodity derivative contracts, net	$ (17,585)	

Expenses

	Years Ended December 31,			Years Ended December 31,		
	2014	**2013**	**2012**	**2014**	**2013**	**2012**
	(in thousands)			(per Boe)		
EXPENSES:						
Lease operating and workover	$ 79,598	$ 73,414	$ 30,500	$ 6.79	$ 8.41	$ 8.34
Gathering and transportation	13,404	5,455		1.14	0.62	
Severance and other taxes	24,266	27,237	24,921	2.07	3.12	6.81
Asset retirement accretion	1,706	1,435	723	0.15	0.17	0.20
Depreciation, depletion, and amortization	269,935	250,396	125,561	23.01	28.67	34.32
Impairment of oil and gas properties	86,471	453,310		7.37	51.91	
General and administrative	48,733	53,250	30,541	4.15	6.10	8.35
Acquisition and transaction costs	4,129	11,803	14,884	0.35	1.35	4.07
Other	5,108	615		0.44	0.07	
Total expenses	**$ 533,350**	**$ 876,915**	**$ 227,130**	**$ 45.47**	**$ 100.42**	**$ 62.09**

Lease Operating and Workover.

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Lease operating and workover expenses increased $6.2 million, or 8%, to $79.6 million for the year ended December 31, 2014 compared to $73.4 million for the year ended December 31, 2013. Lease operating expenses increased $9.2 million, or 14%, to $74.5 million for the year ended December 31, 2014 as compared to $65.3 million for the year ended December 31, 2013. This change is almost entirely attributable to the increase in producing well count for the Mississippian Lime and Anadarko Basin areas year over year; there were approximately 150 more active wells in 2014 for these areas versus the prior year. Workover expenses decreased $3.0 million, or 37%, to $5.1 million for the year ended December 31, 2014, as compared to $8.1 million for the year ended December 31, 2013. The Gulf Coast region workover costs decreased approximately $2.2 million period over period. While the total lease operating and workover expenses increased, the per unit amounts decreased to $6.79 per Boe for the year ended December 31, 2014 from $8.41 per Boe for the year ended December 31, 2013, a decrease of 19%, driven primarily by the 34% increase in production year over year.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Lease operating and workover expenses increased $42.9 million, or 141%, to $73.4 million for the year ended December 31, 2013 compared to $30.5 million for the year ended December 31, 2012.

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Lease operating expenses increased $38.8 million, or 146%, to $65.3 million for the year ended December 31, 2013 as compared to $26.5 million for the year ended December 31, 2012. Lease operating expenses for the year ended December 31, 2013, included a full year of costs related to the assets acquired in the Eagle Property Acquisition (compared to only three months for the year ended December 31, 2012) and seven months of costs related to the assets acquired in the Anadarko Basin Acquisition which closed on May 31, 2013. Of this increase, $31.3 million relates to the increase in producing well count in all areas, which increased approximately 150% year over year due to the Anadarko Basin Acquisition and increased drilling activity in the Mississippian Lime area. The remaining $7.5 million is attributable to surface maintenance and other costs. During 2013, we continued to make investments in our operating areas to reduce lease operating costs, specifically in salt water disposal infrastructure in our Gulf Coast region and in our electrical infrastructure and salt water disposal infrastructure in the Mississippian Lime. Workover expenses increased $4.1 million, or 103%, to $8.1 million for the year ended December 31, 2013, as compared to $4.0 million for the year ended December 31, 2012. Of this increase, approximately $2.9 million relates to the Mississippian Lime area workover costs and $1.3 million relates to the Anadarko area workover costs partially offset by a decrease of $0.1 million in Gulf Coast workover costs. Lease operating and workover expenses increased to $8.41 per Boe for the year ended December 31, 2013 from $8.34 per Boe for the year ended December 31, 2012, an increase of 1%, which was primarily attributable to the factors noted above.

Gathering and Transportation.

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Gathering and transportation expenses increased $7.9 million, or 144%, to $13.4 million for the year ended December 31, 2014 compared to $5.5 million for the year ended December 31, 2013. These expenses are primarily attributable to an amended gas transportation, gathering and processing contract which commenced during the third quarter of 2013 in the Mississippian Lime and included a $0.36 per MMBtu gathering fee based upon wellhead volumes. As such, the year ended December 31, 2013 includes only two quarters of the expense. No gathering and transportation expenses were incurred in 2012.

Severance and Other Taxes.

	Year Ended December 31,		
	2014	2013	2012
		(in thousands)	
Total oil, natural gas, and natural gas liquids sales	$ 653,630	$ 512,753	$ 258,077
Severance taxes	17,723	21,338	22,121
Ad valorem and other taxes	6,543	5,899	2,800
Severance and other taxes	$ 24,266	$ 27,237	$ 24,921
Severance taxes as a percentage of sales	2.7%	4.2%	8.6%
Severance and other taxes as a percentage of sales	3.7%	5.3%	9.7%

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Severance and other taxes decreased $2.9 million, or 11% to $24.3 million for the year ended December 31, 2014 as compared to $27.2 million for the year ended December 31, 2013. Severance taxes decreased $3.6 million, or 17%, to $17.7 million for the year ended December 31, 2014 compared to $21.3 million for the year ended December 31, 2013 and as a percentage of sales, changed from 4.2% for the year ended December 31, 2013 to 2.7% for the corresponding 2014 period due to lower effective severance tax rates in our Mississippian Lime and Anadarko Basin areas and lower production period-over-period in the relatively higher tax Gulf Coast region resulting from reduced drilling activity in 2014 and the Pine Prairie Disposition. Ad valorem taxes increased $0.7 million, or 12%, to $6.6 million for the year ended December 31, 2014, as compared to $5.9 million for the year ended December 31, 2013, related to increased ad valorem taxes in the Anadarko Basin and Gulf Coast area.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Severance and other taxes increased $2.3 million, or 9%, to $27.2 million for the year ended December 31, 2013 as compared to $24.9 million for the year ended December 31, 2012. Severance taxes decreased by $0.8 million, or 4%, and accounted for $21.3 million of the 2013 amount. This decrease was primarily attributable to the geographic production mix, with lower oil, NGL and natural gas sales revenue from the Gulf Coast area, and to higher oil, NGLs and natural gas sales revenue from the Mississippian and Anadarko Basin, where severance tax rates are lower than in the Gulf Coast. Severance taxes for the year ended December 31, 2013 and 2012 were 4.2% and 8.6%, respectively, as a percentage of oil, NGL and natural gas sales revenue.

Ad valorem taxes increased $3.1 million, or 111%, to $5.9 million for the year ended December 31, 2013 as compared to $2.8 million for the year ended December 31, 2012. This change directly correlates to the increase in active well count, which increased approximately 150% year over year due to the Anadarko Basin Acquisition and development drilling in 2013 across all areas.

Depreciation, Depletion and Amortization (DD&A).

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

DD&A expense increased $19.5 million, or 8%, to $269.9 million for the year ended December 31, 2014 compared to $250.4 million for the year ended December 31, 2013. The DD&A rate for the year ended December 31, 2014 was $23.01 per Boe compared to $28.67 per Boe for the year ended December 31, 2013. The increase in total DD&A expense for the year ended December 31, 2014 was primarily due to higher oil, NGLs and natural gas production attributable to a full year of production from the Anadarko Basin Acquisition assets as well as developmental drilling during 2014 in the Mississippian Lime area. The lower DD&A rate per Boe is attributable to the overall growth in proved reserves during 2014.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

DD&A expense increased $124.8 million, or 99%, to $250.4 million for the year ended December 31, 2013 compared to $125.6 million for the year ended December 31, 2012. The DD&A rate for the year ended December 31, 2013 was $28.67 per Boe compared to $34.32 per Boe for the year ended December 31, 2012. The increase in total DD&A expense for the year ended December 31, 2013 was primarily due to higher oil, NGLs and natural gas production attributable to a full year of production from the Mississippian Lime assets acquired in October 2012, the addition of production from the Anadarko Basin Acquisition and developmental drilling during 2013. The lower DD&A rate per Boe is attributable to the addition of reserves with the Anadarko Basin Acquisition, as well as overall growth in proved reserves during 2013.

Impairment of Oil and Gas Properties.

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Our impairment of oil and gas properties pursuant to the full cost "ceiling test" was $83.5 million, net of taxes, for the year ended December 31, 2014 compared to $319.6 million, net of taxes, for the year ended December 31, 2013. The most significant factors affecting the 2014 impairment, which was recorded in the first quarter of 2014, related to the transfer of unevaluated property costs to the full

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cost pool. While we did not record a ceiling test impairment during the fourth quarter of 2014 (as SEC case pricing was still favorable at average prices of $94.99/Bbl for oil and $4.35/MMBtu for natural gas), we would have recorded an additional before tax impairment ranging from $600 million to $800 million at December 31, 2014 if we had used current forward strip pricing from February 2015 in the calculation of the present value of future net revenues from oil and gas properties in determining the full cost ceiling limitation. Should commodity prices remain at their current levels, we will be required to recognize future impairments in the carrying value of oil and gas properties and such impairments may be material.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our impairment of oil and gas properties pursuant to the full cost "ceiling test" was $319.6 million, net of taxes, for the year ended December 31, 2013. There was no impairment for the year ended December 31, 2012.

The most significant factors affecting the impairment related to the transfer of unevaluated property costs to the full cost pool during 2013 and negative reserve revisions in our Gulf Coast area. During 2013, we transferred $61.2 million of Gulf Coast unevaluated property costs to the full cost pool based upon our lack of future plans for further evaluation or development of those leases, and $168.4 million of Mississippian unevaluated property costs attributable to leases that expired during 2013 or that we currently intend to allow to expire in 2014. The negative reserve revisions in our Gulf Coast area were mainly attributable to variability in well performance, our decision during the second quarter to halt further development in our West Gordon field and unfavorable cost revisions.

General and Administrative (G&A).

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Our G&A expenses decreased to $48.7 million for the year ended December 31, 2014 from $53.3 million for the year ended December 31, 2013. The $4.6 million decrease period over period is primarily related to: $2.0 million in additional COPAS recoveries, $11.5 million less in transition services payments (in 2013 and part of 2014, payments were made as a result of the Eagle Property Acquisition and Anadarko Basin Acquisition) and $3.4 million less in other taxes, partially offset by an increase of $10.1 million in employee costs (including salary, bonus, severance related to the Houston office closure and share-based compensation) and $2.2 million of other G&A costs.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our G&A expenses increased to $53.3 million for the year ended December 31, 2013 from $30.5 million for the year ended December 31, 2012. The increase in G&A expenses of $22.8 million, or 75%, was primarily due to salary, benefits, and other expenses of $10.7 million related to the increase in headcount, which increased from 93 full-time employees at December 31, 2012 to 217 full-time employees at December 31, 2013; an increase in payments made under the Eagle Transition Services Agreement of $0.6 million; payments made under the Panther Transition Services Agreement of $10.2 million; and other costs of $1.3 million.

Acquisition and Transaction Costs.

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Our acquisition and transaction costs decreased by $7.7 million to $4.1 million for the year ended December 31, 2014 from $11.8 million for the year ended December 31, 2013. For the 2014 period, these costs generally represent our expenses related to the Pine Prairie Disposition discussed above.

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For the 2013 period, these costs represent our expenses related to the Anadarko Basin Acquisition discussed above.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Our acquisition and transaction costs decreased by $3.1 million for the year ended December 31, 2013 from $14.9 million for the year ended December 31, 2012. These total costs of $11.8 million incurred in 2013 represent our expenses through December 31, 2013 related to the Anadarko Basin Acquisition and are primarily attributable to due diligence, legal and other advisory fees that are required to be expensed under US GAAP.

Other.

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Other operating expenses for the year ended December 31, 2014 were $5.1 million, compared to $0.6 million for the year ended December 31, 2013. These expenses represent the loss on disposal of, or market value adjustments to, field equipment inventory deemed no longer useful to current operations, penalty fees associated with the early termination of a drilling contract, as well as other miscellaneous expenses.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Other operating expenses for the year ended December 31, 2013 were $0.6 million, compared to no related costs for the year ended December 31, 2012. These costs represent the loss on disposal of, or market value adjustments to, field equipment inventory deemed no longer useful to current operations.

Other Income (Expense)

	Years Ended December 31,		
	2014	**2013**	**2012**
		(in thousands)	
OTHER INCOME (EXPENSE)			
Interest income	$ 39	$ 33	$ 245
Interest expense	(149,962)	(115,383)	(24,174)
Capitalized Interest	12,414	32,245	11,175
Interest expense net of amounts capitalized	(137,548)	(83,138)	(12,999)
Total other income (expense)	**$ (137,509)**	**$ (83,105)**	**$ (12,754)**

Interest Expense

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Interest expenses, before capitalized interest, for the years ended December 31, 2014 and 2013 was $150.0 million and $115.4 million, respectively. The increase in interest expense was primarily due to a full year of interest associated with the 2021 Senior Notes (as discussed below) issued in 2013. Our average outstanding balance under our revolving credit facility was $386.7 million during the year ended December 31, 2014, compared to $252.7 million the year ended December 31, 2013, and related to $12.7 million of the total interest expense of $150.0 million for the year ended December 31, 2014. Of the remainder, $64.9 million was interest incurred under the 2021 Senior Notes, $64.5 million was interest incurred under the 2020 Senior Notes and $7.9 million represented amortization of deferred financing costs. Of the total interest expense, $12.4 million and $32.2 million was capitalized to oil and gas properties, resulting in $137.6 million and $83.1 million in interest expense, net of capitalized interest, for the years ended December 31, 2014 and 2013, respectively.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Interest expense (before capitalized interest) for the years ended December 31, 2013 and 2012 was $115.4 million and $24.2 million, respectively. The increase in 2013 interest expense was primarily due to the issuance during 2013 of the 2021 Senior Notes (as discussed below) and a full year of interest expense associated with the 2020 Senior Notes (as discussed below) issued during 2012, in addition to a higher average outstanding balance under our revolving credit facility during the 2013 period. Our average outstanding balance under our revolving credit facility was $252.7 million during the 2013 period, versus $160.0 million for the 2012 period, and related to $7.1 million of the total interest expense of $115.4 million. The remainder of the interest expense for the year ended December 31, 2013, $108.3 million, related to interest expense of $37.8 million on the 2021 Senior Notes, $64.5 million on the 2020 Senior Notes, and amortization of deferred financing costs of $6.0 million. Of total interest expense, $32.2 million and $11.2 million was capitalized, resulting in $83.1 million and $13.0 million in net interest expense for years ended December 31, 2013 and 2012, respectively.

Provision for Income Taxes.

Year Ended December 31, 2014 as Compared to the Year Ended December 31, 2013

Income tax expense was $6.4 million for the year ended December 31, 2014. This represents an application of our estimated effective tax rate (including state income taxes) for the year ended December 31, 2014 of 5.2% to the income incurred throughout the year. The significant reasons for the change from an income tax benefit to an expense during the year ended December 31, 2014 was $157.5 million of net unrealized gains on commodity derivative contracts which resulted in pre-tax book income of $123.3 million.

The effective tax rate of 5.2% for the year ended December 31, 2014 includes the impact of a $39.9 million reduction in the valuation allowance originally established against our federal tax net operating losses ("NOL") attributable to the unrealized hedging gains during 2014 as discussed above.

Year Ended December 31, 2013 as Compared to the Year Ended December 31, 2012

Income tax benefit was $146.5 million for the year ended December 31, 2013. This represents an application of our estimated effective tax rate (including state income taxes) for the year ended December 31, 2013 of 29.9% to the loss incurred throughout the year. The significant reasons for the change from an income tax expense to a benefit during the year ended December 31, 2013 were the absence of a change in tax status charge during 2013 (as this event took place in 2012), and the occurrence of a book loss for the year ended December 31, 2013.

In light of the impairment of oil and gas properties, we have recorded a $45.7 million valuation allowance against our federal and State of Louisiana tax NOLs, as we do not believe that it is more-likely-than-not that this portion of our NOLs are realizable. We believe that the balance of the NOLs are realizable only to the extent of future taxable income primarily related to the excess of book carrying value of properties over their respective tax bases. No other sources of future taxable income are considered in this judgment.

Liquidity and Capital Resources

Our financial statements have been prepared on a going concern basis, which contemplates continuity of operations, realization of assets and the satisfaction of liabilities in the normal course of business. The content below and under "Risks, Uncertainties, and Going Concern" above addresses

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important factors affecting our financial condition, liquidity and capital resources and debt covenant compliance.

At June 30, 2015, our liquidity consisted of approximately $250.9 million of available borrowing capacity under our credit facility and $151.0 million of cash and cash equivalents.

Expenditures for exploration and development of oil and natural gas properties and payments for interest related to our outstanding debt are the primary use of our capital resources and liquidity. We expect to invest a total of between $250.0 million and $275.0 million of capital for exploration, development and lease and seismic acquisition during the year ending December 31, 2015. Additionally, we expect to capitalize between $4.0 million and $6.0 million of interest expense during that same period.

In April 2015, we closed a purchase and sale agreement covering the sale of our remaining producing assets in Louisiana for total consideration of approximately $42.4 million cash, net of customary closing adjustments. The net proceeds will be used for general corporate purposes.

On May 21, 2015, we issued $625.0 million of Second Lien Notes and utilized the proceeds to repay the outstanding balance of the credit facility in an amount of approximately $468.2 million, with the remainder to be utilized for general corporate purposes. Further, we exchanged approximately $504.121 million of Third Lien Notes for approximately $279.8 million of 2020 Senior Notes and $350.3 million of 2021 Senior Notes, representing an exchange at 80.0% of the exchanged Senior Unsecured Notes' par value. Additionally, on June 2, 2015, the Company exchanged approximately $20.0 million of Third Lien Notes for approximately $26.6 million of 2020 Senior Notes and $2.0 million of 2021 Senior Notes, representing an exchange at 70.0% of the exchanged Senior Unsecured Notes' par value. Approximately $63.9 million of the principal amount of 2020 Senior Notes and $70.7 million of the principal amount of 2021 Senior Notes were extinguished as a result of the exchanges occurring at a percentage of the Senior Unsecured Notes' par value.

Additionally, we and Midstates Sub also entered into the Seventh Amendment which provided that upon completion of the offering of the Second Lien Notes and Third Lien Notes exchange, the borrowing base of the credit facility would be reduced to $252.4 million. The Seventh Amendment also provided additional covenant flexibility.

Our interest payment obligations are substantial. The table below summarizes the cash interest payments on our various debt facilities as of June 30, 2015 (in thousands):

	2020 Senior Notes	2021 Senior Notes	Second Lien Notes	Third Lien Notes	Total
Remainder of 2015	$ 10,521	$ 16,079	$ 32,986	$ 27,663	$ 87,249
2016	31,565	32,158	62,500	53,230	179,453
2017	31,565	32,158	62,500	54,300	180,523
2018	31,565	32,158	62,500	55,391	181,614
2019	31,565	32,158	62,500	56,504	182,727
2020	31,565	32,158	31,250	83,830	178,803
2021		16,079			16,079

Our future success in growing proved reserves and production and meeting our interest obligations will be highly dependent on our ability to access additional outside sources of capital, via either the debt or equity markets, through growth in our credit facility or by securing other external sources of funding. Though we have no current plans to do so, we may from time to time seek to retire, purchase or exchange our outstanding debt in open market purchases, privately negotiated transactions or otherwise. Such repurchases or exchanges, if any, will depend on prevailing market conditions, our liquidity requirements, contractual restrictions and other factors. The amounts involved may be material.

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Significant Sources of Capital

Reserve-based Credit Facility

We maintain a $750.0 million credit facility with a borrowing base of $252.4 million supported by our Mississippian Lime and Anadarko Basin oil and gas assets. At June 30, 2015, we had no amounts drawn on the credit facility and had outstanding letters of credit obligations totaling $1.5 million.

The credit facility matures on May 31, 2018 and borrowings thereunder are secured by substantially all of our oil and natural gas properties and bear interest at LIBOR plus an applicable margin, depending upon the Company's borrowing base utilization, between 2.00% and 3.00% per annum. At June 30, 2015 and 2014, the weighted average interest rate was 2.9% and 2.8%, respectively.

In addition to interest expense, the credit facility requires the payment of a commitment fee each quarter. The commitment fee is computed at the rate of either 0.375% or 0.500% per annum based on the average daily amount by which the borrowing base exceeds the outstanding borrowings during each quarter.

The borrowing base under the credit facility is subject to semiannual redeterminations in April and October and up to one additional time per six month period following each scheduled borrowing base redetermination, as may be requested by us or the administrative agent, acting on behalf of lenders holding at least two-thirds of the outstanding loans and other obligations.

Under the terms of the credit facility, we are required to repay any amount by which the principal balance of its outstanding loans and its letter of credit obligations exceed its redetermined borrowing base or grant liens on additional property having sufficient value to eliminate such excess. We are permitted to make such repayment in six equal successive monthly payments commencing 30 days following the administrative agent's notice regarding such borrowing base reduction.

On March 24, 2015, we and Midstates Sub entered into a Sixth Amendment (the "Sixth Amendment") to the credit facility. The Sixth Amendment amended the required ratio of net consolidated indebtedness to EBITDA under the Credit Agreement for each of the fiscal quarters in 2015 from 4.0:1.0 to 4.5:1.0. Additionally, the Sixth Amendment amended the mortgage requirements under the credit facility to provide for an increase from 80% to 90% for the percentage of properties included in the borrowing base that are required to be subject to mortgages for the benefit of the lenders.

On May 21, 2015, we and Midstates Sub entered into a Seventh Amendment (the "Seventh Amendment") to the credit facility. The Seventh Amendment provided that, with the completion of the offering of the Second Lien Notes and Third Lien Notes exchange (both discussed below), our borrowing base would be reduced to approximately $252.4 million. The Seventh Amendment also eliminated the required ratio of net consolidated indebtedness to EBITDA covenant and added a ratio of Total Senior Indebtedness (as defined therein) to EBITDA of not more than 1.0:1.0. The next scheduled redetermination of the borrowing base is October 2015.

On August 5, 2015, we and Midstates Sub entered into an Eighth Amendment (the "Eighth Amendment") to the credit facility. The Eighth Amendment increases the limitation on certain leases and lease agreements into which Midstates and Midstates Sub may enter into in any period of twelve consecutive calendar months during the life of such leases from $2,000,000 to $3,500,000.

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2020 Senior Notes

On October 1, 2012, we issued $600 million in aggregate principal amount of 2020 Senior Notes conducted pursuant to Rule 144A and Regulation S under the Securities Act of 1933, as amended (the "Securities Act"). In October 2013, these notes were exchanged for an equal principal amount of identical registered notes. The 2020 Senior Notes rank pari passu in right of payment with the 2021 Senior Notes, the Second Lien Notes and Third Lien Notes. The 2020 Senior Notes were co-issued on a joint and several basis by us and our wholly owned subsidiary, Midstates Sub. We do not have any operations or independent assets other than its 100% ownership interest in Midstates Sub and there are no other subsidiaries. The indenture governing the 2020 Senior Notes (the "2020 Senior Notes Indenture") does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans to us or limit our ability to advance loans to Midstates Sub. On May 21, 2015 and June 2, 2015, a total of approximately $306.4 million of 2020 Senior Notes were exchanged for Third Lien Notes, as discussed above.

At any time prior to October 1, 2015, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2020 Senior Notes with the net proceeds of a public or private equity offering at a redemption price of 110.75% of the principal amount of the 2020 Senior Notes, plus any accrued and unpaid interest up to the redemption date. In addition, at any time before October 1, 2016, we may redeem all or a part of the 2020 Senior Notes at a redemption price equal to 100% of the principal amount of 2020 Senior Notes redeemed plus the Applicable Premium (as defined in the 2020 Senior Notes Indenture) at the redemption date, plus any accrued and unpaid interest, if any, up to the redemption date. On or after October 1, 2016, we may redeem all or a part of the 2020 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the 2020 Senior Notes Indenture plus accrued and unpaid interest, if any, on the 2020 Senior Notes redeemed, up to the redemption date.

Upon the occurrence of certain change of control events, as defined in the 2020 Senior Notes Indenture, each holder of the 2020 Senior Notes will have the right to require that we repurchase all or a portion of such holder's 2020 Senior Notes in cash at a purchase price equal to 101% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

2021 Senior Notes

On May 31, 2013, we issued $700.0 million in aggregate principal amount of 2021 Senior Notes. In October 2013, these notes were exchanged for an equal principal amount of identical registered notes. The 2021 Senior Notes rank pari passu in right of payment with the 2020 Senior Notes, Second Lien Notes and Third Lien Notes. The 2021 Senior Notes were co-issued on a joint and several basis by us and our wholly owned subsidiary, Midstates Sub. The indenture governing the 2021 Senior Notes (the "2021 Senior Notes Indenture") does not create any restricted assets within Midstates Sub, nor does it impose any significant restrictions on the ability of Midstates Sub to pay dividends or make loans us or limit our ability to advance loans to Midstates Sub. On May 21, 2015 and June 2, 2015, a total of approximately $352.3 million of 2021 Senior Notes were exchanged for Third Lien Notes, as discussed above.

Prior to June 1, 2016, we may, under certain circumstances, redeem up to 35% of the aggregate principal amount of the 2021 Senior Notes (less the amount of 2021 Senior Notes redeemed pursuant to the preceding paragraph) with the net proceeds of any equity offerings at a redemption price of 109.25% of the principal amount of the 2021 Senior Notes redeemed, plus any accrued and unpaid interest, if any, up to the redemption date. In addition, at any time before June 1, 2016, we may redeem all or a part of the 2021 Senior Notes at a redemption price equal to 100% of the principal amount of the 2021 Senior Notes redeemed plus the Applicable Premium (as defined in the 2021 Senior Notes Indenture) at the redemption date, plus any accrued and unpaid interest, if any, up to, the redemption date. On or after October 1, 2016, we may redeem all or a part of the 2021 Senior Notes at varying redemption prices (expressed as percentages of principal amount) set forth in the 2021 Senior Notes Indenture plus accrued and unpaid interest, if any, on the 2021 Senior Notes redeemed, up to, the redemption date.

Upon the occurrence of certain change of control events, as defined in the 2021 Senior Notes Indenture, each holder of the 2021 Senior Notes will have the right to require that we repurchase all or a portion of such holder's 2021 Senior Notes in cash at a purchase price equal to 101% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

Second Lien Notes

On May 21, 2015, we and Midstates Sub issued and sold $625.0 million aggregate principal amount of Second Lien Notes in a private placement conducted pursuant to Rule 144A under the Securities Act. The Second Lien Notes mature on the earlier of June 1, 2020 or 12 months after the maturity date of the Company's credit facility (including any extension or refinancing of such facility). The Second Lien Notes have an interest rate of 10.0% and interest is payable semi-annually on June 1 and December 1 of each fiscal year. The Second Lien Notes are unconditionally guaranteed, jointly and severally, on a senior secured basis by each of our future restricted subsidiaries (the "Guarantors") and will be initially secured by second-priority liens on substantially all of our and the Guarantors' assets that secure our credit facility.

On May 21, 2015, in connection with the offering of Second Lien Notes, we and Midstates Sub entered into a registration rights agreement with the initial purchasers of the Second Lien Notes pursuant to which the Issuers are obligated, within 270 days after the issuance of the Second Lien Notes, to file with the Securities and Exchange Commission under the Securities Act a registration statement with respect to an offer to exchange the Second Lien Notes for substantially identical registered new notes. We will be obligated to pay liquidated damages consisting of additional interest on the Second Lien Notes if, within the periods specified in the agreement, it does not file the exchange offer registration statement or if certain other events occur.

The Second Lien Notes are our senior secured obligations and rank effectively junior to its obligations under the credit facility, effectively senior to its existing and future unsecured indebtedness, effectively senior to our Third Lien Notes and all future junior lien obligations, effectively junior to all existing and future secured indebtedness secured by assets not constituting collateral under the Second Lien Notes, pari passu with all of our existing and future senior debt, structurally subordinated to all existing and future indebtedness of any non-Guarantor subsidiaries and senior to any existing or future subordinated debt.

Upon the occurrence of certain change of control events, as defined in the indenture governing the Second Lien Notes, each holder of the Second Lien Notes will have the right to require that we repurchase all or a portion of such holder's 2020 Second Lien Notes in cash at a purchase price equal to 101% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

Third Lien Notes

On May 21, 2015 and June 2, 2015, we issued approximately $504.121 million and $20.0 million, respectively, in aggregate principal amount of Third Lien Notes in a private placement and in exchange for an aggregate of $306.4 million of the 2020 Senior Notes and $352.3 million of the 2021 Senior Notes. The Third Lien Notes are unconditionally guaranteed, jointly and severally, on a senior secured basis by each of the Guarantors. The Third Lien Notes are initially secured by third-priority liens on substantially all of the Company's assets that secure the credit facility. The Third Lien Notes have an interest rate of 12.0%, consisting of cash interest of 10.0% and paid-in-kind interest of 2.0%, per annum and mature on the earlier of June 1, 2020 or 12 months after the maturity date of our credit facility (including any extension or refinancing of such facility). Interest is payable semi-annually on June 1 and December 1 of each fiscal year.

On May 21, 2015, in connection with the issuance of the Third Lien Notes, we entered into a registration rights agreement with the initial purchasers of the Third Lien Notes pursuant to which we are obligated, within 270 days after the issuance of the Third Lien Notes, to file with the Securities and Exchange Commission under the Securities Act a registration statement with respect to an offer to exchange the Third Lien Notes for substantially identical registered new notes. We will be obligated to pay liquidated damages consisting of additional interest on the Third Lien Notes if, within the periods specified in the agreement, it does not file the exchange offer registration statement or if certain other events occur.

The Third Lien Notes are senior secured obligations of the Company and rank effectively junior to its obligations under the credit facility and Second Lien Notes to the extent of the value of the collateral securing such indebtedness, effectively senior to its existing and future unsecured indebtedness to the extent of the value of the collateral securing the Third Lien Notes, effectively senior to all future junior lien obligations that rank below a third-priority basis to the extent of the value of the collateral securing the Third Lien Notes, effectively junior to all existing and future secured indebtedness secured by assets not constituting collateral under the Third Lien Notes, equal in right of payment to all of the Company's existing and future senior debt, structurally subordinated to all existing and future indebtedness of any non-Guarantor subsidiaries and senior in right of payment to any existing or future subordinated debt.

Upon the occurrence of certain change of control events, as defined in the indenture governing the Third Lien Notes, each holder of the Third Lien Notes will have the right to require that we repurchase all or a portion of such holder's Third Lien Notes in cash at a purchase price equal to 101% of the aggregate principal amount thereof plus any accrued and unpaid interest to the date of repurchase.

Debt Covenants

The indentures governing the 2020 Senior Notes, 2021 Senior Notes, Second Lien Notes and Third Lien Notes contain covenants that, among other things, restrict our ability to: (i) incur additional indebtedness, guarantee indebtedness or issue certain preferred shares; (ii) make loans, investments and other restricted payments; (iii) pay dividends on or make other distributions in respect of, or repurchase or redeem, capital stock; (iv) create or incur certain liens; (v) sell, transfer or otherwise dispose of certain assets; (vi) enter into certain types of transactions with our affiliates; (vii) consolidate, merge or sell substantially all of our assets; (viii) prepay, redeem or repurchase certain debt; (ix) alter the business we conduct and (x) enter into agreements restricting the ability of our current and any future subsidiaries to pay dividends.

Additionally, the credit facility, as amended, contains, among other standard affirmative and negative covenants, financial covenants including a maximum ratio of Total Senior Indebtedness to EBITDA (as defined therein) of not more than 1.0:1.0 and a minimum current ratio (as defined therein) of not less than 1.0 to 1.0. The credit facility also limits our ability to make any dividends, distributions or redemptions.

Cash Flows from Operating, Investing and Financing Activities Six Months Ended June 30, 2015 Compared to Six Months Ended June 30, 2014

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods presented. For information regarding the individual components of

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our cash flow amounts, please refer to the Unaudited Condensed Consolidated Statements of Cash Flows included in this prospectus.

Our operating cash flows are sensitive to a number of variables, the most significant of which is the volatility of oil and gas prices. Regional and worldwide economic activity, weather, infrastructure capacity to reach markets and other variable factors significantly impact the prices of these commodities. These factors are beyond our control and are difficult to predict. For additional information on the impact of changing prices on our financial position, see " Quantitative and Qualitative Disclosures About Market Risk."

The following information highlights the significant period-to-period variances in our cash flow amounts (table in thousands):

	For the Six Months Ended June 30, 2015	2014
Net cash provided by operating activities	$ 138,650	$ 173,561
Net cash used in investing activities	(149,994)	(128,028)
Net cash provided by (used in) financing activities	150,824	(49,036)
Net change in cash	**$ 139,480**	**$ (3,503)**

Cash flows provided by operating activities

Net cash provided by operating activities decreased by $34.9 million to $138.7 million for the six months ended June 30, 2015 as compared to $173.6 million for the six months ended June 30, 2014. The decrease in net cash provided by operating activities was primarily the result of a decrease in our oil and gas revenues of $163.2 million due to lower commodity pricing, offset partially by increased settlements of derivatives of $126.8 million.

Cash flows used in investing activities

Net cash used in investing activities was $150.0 million and $128.0 million during the six months ended June 30, 2015 and 2014, respectively. The increase in net cash used in investing activities was primarily the result of a decrease in proceeds from the sale of oil and gas properties of $105.0 million offset by a decrease in capital expenditures of $85.3 million. During the 2014 period, the Company completed the Pine Prairie disposition for approximately in $147.5 million in proceeds as compared to the Dequincy Divestiture that occurred during the 2015 period for approximately $40.3 million in proceeds. The decrease in our capital expenditures is a result of lower rig count during the 2015 period due to low commodity pricing.

Cash flows provided by (used in) financing activities

Net cash provided by financing activities was $150.8 million for the six months ended June 30, 2015, as compared to cash used in financing activities of $49.0 million for the six months ended June 30, 2014. The increase in net cash provided by financing activities was primarily the result of the issuance of the Second Lien Notes of $625.0 million and additional borrowings from the credit facility of $33.0 million offset partially by the repayment of the credit facility of $468.2 million and debt restructuring costs of $36.1 million during the 2015 period as compared to borrowings from the credit facility of $84.0 million and repayments of the credit facility of $131.0 million during the 2014 period.

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Cash Flows from Operating, Investing and Financing Activities Year Ended December 31, 2014 Compared to Year Ended December 31, 2013 and Year Ended December 31, 2013 Compared to Year Ended December 31, 2012

The following table summarizes our consolidated cash flows from operating, investing and financing activities for the periods presented. For information regarding the individual components of our cash flow amounts, please refer to the Audited Consolidated Statements of Cash Flows included in this prospectus.

The following information highlights the significant period-to-period variances in our cash flow amounts (table in thousands):

	For the Years Ended December 31,		
	2014	**2013**	**2012**
Net cash provided by operating activities	$ 351,544	$ 237,588	$ 145,019
Net cash used in investing activities	(404,264)	(1,204,332)	(781,378)
Net cash provided by financing activities	31,114	981,029	647,893
Net change in cash	**$ (21,606)**	**$ 14,285**	**$ 11,534**

Cash flows provided by operating activities

Net cash provided by operating activities was $351.5 million, $237.6 million and $145.0 million for the years ended December 31, 2014, 2013 and 2012, respectively. The increase in net cash provided by operating activities for the year ended December 31, 2014 compared to the year ended December 31, 2013 was primarily the result of an increase in oil and natural gas revenues attributable to higher production and favorable working capital changes, partially offset by lower realized commodity prices. The increase in net cash provided by operating activities for the year ended December 31, 2013 compared to the year ended December 31, 2012 was primarily driven by an increase in production in all commodities and an increase in natural gas prices, partially offset by a decrease in oil and NGL prices.

Cash flows used in investing activities

We had net cash used in investing activities of $404.3 million, $1.2 billion and $781.4 million during the years ended December 31, 2014, 2013 and 2012, respectively, as a result of our capital expenditures for drilling, development and acquisition costs. During the year ended December 31, 2014, $561.7 million was spent on our drilling program, partially offset by $147.7 million in proceeds received for the Pine Prairie Disposition, $3.0 million in proceeds received related to the Exploration Agreement with PetroQuest and $1.4 million in other asset sales. During the year ended December 31, 2013, $573.7 million was spent on our drilling program and $620.1 million for the Anadarko Basin Acquisition. The increase in net cash used in investing activities during the year ended December 31, 2013 compared to the year ended December 31, 2012 was primarily due to the Anadarko Basin Acquisition and continued expansion of our drilling programs.

Cash flows provided by financing activities

Net cash provided by financing activities was $31.1 million, $981.0 million and $647.9 million for the years ended December 31, 2014, 2013 and 2012, respectively. For the year ended December 31, 2014, we had draws on the revolver of $165.0 million and repayments (using a portion of the proceeds from the Pine Prairie Disposition) of $131.0 million. For the year ended December 31, 2013, cash sourced through financing activities was provided primarily from net long-term borrowings of $1.0 billion, consisting of the 2021 Senior Notes of $700 million and borrowings under the revolver of

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$341.5 million, offset by repayments of our revolving credit facility of $34.3 million. For the year ended December 31, 2012, cash sourced through financing activities was provided primarily from proceeds from our initial public offering of $213.6 million and net long-term borrowings of $459.2 million, consisting of the 2020 Senior Notes of $600 million and advances from our revolving credit facility, offset by repayments of our revolving credit facility during the year. Our long-term debt was $1.7 billion, $1.7 billion and $694.0 million at December 31, 2014, 2013 and 2012, respectively.

Critical Accounting Policies and Estimates

We prepare our financial statements and the accompanying notes in conformity with GAAP, which requires our management to make estimates and assumptions about future events that affect the reported amounts in our financial statements and the accompanying notes. We identify certain accounting policies as critical based on, among other things, their impact on the portrayal of our financial condition, results of operations or liquidity and the degree of difficulty, subjectivity and complexity in their deployment. Critical accounting policies cover accounting matters that are inherently uncertain because the future resolution of such matters is unknown. Our management routinely discusses the development, selection and disclosure of each of the critical accounting policies.

When used in the preparation of our financial statements, estimates are based on our current knowledge and understanding of the underlying facts and circumstances and may be revised as a result of actions we take in the future. Changes in these estimates will occur as a result of the passage of time and the occurrence of future events. Subsequent changes in these estimates may have a significant impact on our condensed consolidated financial position, results of operations and cash flows. Following is a discussion of our most critical accounting policies:

Reserves Estimates. Proved oil and gas reserves are the estimated quantities of natural gas, crude oil and NGLs that geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing operating conditions and government regulations. Proved undeveloped reserves include those reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Undeveloped reserves may be classified as proved reserves on undrilled acreage directly offsetting development areas that are reasonably certain of production when drilled, or where reliable technology provides reasonable certainty of economic producibility. Undrilled locations may be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time.

Despite the inherent imprecision in these engineering estimates, our reserves are used throughout our financial statements. For example, since we use the units-of-production method to amortize our oil and gas properties, the quantity of reserves could significantly impact our DD&A expense. Our oil and gas properties are also subject to a "ceiling" limitation based in part on the quantity of our proved reserves. Finally, these reserves are the basis for our supplemental oil and gas disclosures.

Reserves as of December 31, 2014, 2013 and 2012 were calculated using an unweighted arithmetic average of commodity prices in effect on the first day of each month, held flat for the life of the production, except where prices are defined by contractual arrangements.

We have elected not to disclose probable and possible reserves or reserve estimates in this filing.

Revenue Recognition. Our revenue recognition policy is significant because revenue is a key component of the results of operations and of the forward-looking statements contained in the analysis of liquidity and capital resources. We record revenue in the month our production is delivered to the purchaser, but payment is generally received 30 to 90 days after the date of production. At the end of each month, we estimate the amount of production that was delivered to the purchaser and the price that will be received. We use our knowledge of our properties, their historical performance, the anticipated effect of weather conditions during the month of production, NYMEX and local spot market prices and other factors as the basis for these estimates. We record the variances between our estimates and the actual amounts received in the month payment is received.

Share-Based Compensation. We account for share-based compensation awards in accordance with FASB ASC 718, Compensation Stock Compensation. We measure share-based compensation cost at fair value and generally recognize the corresponding compensation expense on a straight-line basis over the service period during which awards are expected to vest. We include share-based compensation expense in "General and administrative expense" in our consolidated statements of operations.

Financial Instruments. Our financial instruments consist of cash and cash equivalents, receivables, payables, debt, and commodity derivatives. Commodity derivatives are recorded at fair value. The carrying amount of our other financial instruments approximate fair value because of the short-term nature of the items or variable pricing.

Derivative financial instruments are recorded in our consolidated balance sheets as either an asset or liability measured at estimated fair value. Changes in the derivative's fair value are recognized currently in earnings as gains and losses in the period of change. The gains or losses are recorded within revenues in "Gains (losses) on commodity derivative contracts net." The related cash flow impact is reflected within cash flows from operating activities.

Asset Retirement Obligations. We have obligations to remove tangible equipment and facilities associated with our oil and natural gas wells, and to restore land at the end of oil and natural gas production operations. The removal and restoration obligations are associated with plugging and abandoning wells. Estimating the future restoration and removal costs is difficult and requires us to make estimates and judgments because most of the removal obligations are many years in the future and contracts and regulations often have vague descriptions of what constitutes removal. Asset removal technologies and costs are constantly changing, as are regulatory, political, environmental, safety and public relations considerations. Inherent in the present value calculations are numerous assumptions and judgments including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlements and changes in the legal, regulatory, environmental and political environments.

Recent Accounting Pronouncements. We reviewed recently issued accounting pronouncements that became effective during the year ended December 31, 2014, and determined that none would have a material impact on our condensed consolidated financial statements, with the exception of ASU 2014-09, "Revenue from Contracts with Customers" and ASU 2014-15, "Presentation of Financial Statements Going Concern," (both effective for annual reporting periods beginning after December 15, 2016), which we are still evaluating.

Off-Balance Sheet Arrangements. Currently, we do not have any off-balance sheet arrangements as defined under Item 303(a)(4) (ii) of Regulation S-K.

Quantitative and Qualitative Disclosures About Market Risk

We are exposed to a variety of market risks including commodity price risk, interest rate risk and counterparty and customer risk. We address these risks through a program of risk management including the use of derivative instruments.

The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The disclosures are not meant to be precise indicators of expected future losses or gains, but rather indicators of reasonably possible losses or gains. This forward-looking information provides indicators of how we view and manage our ongoing market risk exposures. All of our market risk sensitive instruments were entered into for

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purposes other than speculative trading. These derivative instruments are discussed in Note 4 Risk Management and Derivative Instruments in the Notes to the Unaudited Condensed Consolidated Financial Statements included in this prospectus.

Commodity Price Exposure. We are exposed to market risk as the prices of oil and natural gas fluctuate due to changes in supply and demand. To partially reduce price risk caused by these market fluctuations, we have hedged in the past and expect to hedge a significant portion of our future production. However, given the current low commodity price environment, we may limit the extent of our hedging program in the near-term as appropriate.

We utilize derivative financial instruments to manage risks related to changes in oil and natural gas prices. As of June 30, 2015, we utilized fixed price swaps to reduce the volatility of oil and natural gas prices on a portion of our future expected oil and natural gas production.

For derivative instruments recorded at fair value, the credit standing of our counterparties is analyzed and factored into the fair value amounts recognized on the balance sheet.

The following is a summary of our commodity derivative contracts as of June 30, 2015:

	Hedged Volume	Weighted-Average Fixed Price
Oil (Bbls):		
WTI Swaps 2015	2,208,000	$ 71.56
Natural Gas (MMBtu):		
Swaps 2015(1)	9,200,000	$ 4.13

(1) Includes 1,500,000 MMBtus in natural gas swaps that priced during the period, but had not cash settled as of June 30, 2015.

	As of and for the Six Months Ended June 30, 2015
	(in thousands)
Derivative fair value at period end asset (included in balance sheet)	$ 33,991
Realized net gain (included in the statement of operations)	$ 94,797
Unrealized net loss (included in the statement of operations)	$ 92,718

At June 30, 2015 and December 31, 2014, all of our commodity derivative contracts were with seven bank counterparties. Our policy is to net derivative liabilities and assets where there is a legally enforceable master netting agreement with the counterparty.

Interest Rate Risk. At June 30, 2015, we had no indebtedness outstanding under our credit facility, $293.6 million outstanding in 2020 Senior Notes, which bear interest at 10.75%, $347.7 million outstanding in 2021 Senior Notes, which bear interest at 9.25%, $625.0 million outstanding in Second Lien Notes, which bear interest at 10.0% and $525.3 million in Third Lien Notes, which bear interest at 12.0%. At June 30, 2015 and 2014, the weighted average interest rate was 2.9% and 2.8%, respectively, for the credit facility.

A 1.0% increase in each of the average LIBOR and federal funds rate for the three and six months ended June 30, 2014 would have resulted in an estimated $1.0 million and $1.9 million, respectively, increase in interest expense, of which a portion may be capitalized. There were no borrowings on the credit facility as of June 30, 2015.

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At June 30, 2015, we do not have any interest rate derivatives in place. In the future, we may utilize interest rate derivatives to mitigate our exposure to change in interest rates. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio.

Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

None.

Controls and Procedures

Evaluation of Disclosure Controls and Procedures

During the second quarter of 2015, our management carried out an evaluation of the effectiveness of the design and operation of our disclosure controls and procedures pursuant to Exchange Act Rule 13a-15. Our disclosure controls and procedures are designed to provide reasonable assurance that information required to be disclosed in the reports we file with the SEC is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC, and that such information is accumulated and communicated to our management, including our President and Chief Executive Officer and our Executive Vice President and Chief Financial Officer, as appropriate, to allow timely decisions regarding required disclosures. As a result of the material weakness described below, our Chief Executive Officer and Chief Financial Officer concluded that our disclosure controls and procedures were not effective at a reasonable level of assurance as of June 30, 2015. Notwithstanding such material weakness, management concluded that the financial statements and other financial information included in this report present fairly, in all material respects, the financial condition, results of operations and cash flows for all periods presented.

Material Weakness in Internal Control over Financial Reporting and Remediation Efforts

During the second quarter of 2015, we identified a material weakness in our internal control over financial reporting related to the review of our Consolidated Statements of Cash Flows. This material weakness resulted from errors in our restated amounts within our Consolidated Statements of Cash Flows for the years ended December 31, 2014, 2013 and 2012, which were reported in Item 5. *Other Information,* of our First Quarter 2015 Quarterly Report.

Although we continue to believe that these errors are immaterial, we have revised the restated amounts for the years ended December 31, 2013 and 2012 in Item 5. Other Information, of our Second Quarter 2015 Quarterly Report. There continues to be no impact to the Consolidated Balance Sheets as of December 31, 2014 and 2013, or the Consolidated Statements of Operations for the years ended December 31, 2014, 2013 and 2012. If not remediated, this material weakness could result in a material misstatement of the Consolidated Statements of Cash Flows.

Changes in Internal Control over Financial Reporting

Except for the remediation efforts described below, there were no changes in our internal control over financial reporting during the quarter ended June 30, 2015 that have materially affected, or are reasonably likely to materially affect, our internal control over financial reporting.

Upon identification of the errors in Item 5. *Other Information*, of our First Quarter 2015 Quarterly Report, we began remediation efforts to improve our internal controls. We have implemented additional review procedures targeted to ensuring the completeness and accuracy of our Consolidated Statements of Cash Flows. Our remediation efforts are still in progress. The implementation of these changes to our control environment is ongoing, and our remediation efforts have not yet been subject to management's testing.

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Other Items

Contractual Obligations

The following table summarizes our contractual obligations as of June 30, 2015 (in thousands):

	Payments Due by Period(1)				
	Total	Less than 1 year	1 - 3 years	3 - 5 years	More than 5 years
Long-Term Debt:					
Principal	$ 1,790,398	$	$	$ 1,790,398	$
Interest(2)	1,022,213	180,037	551,550	290,626	
Drilling contracts	10,697	10,697			
Non-cancellable office lease commitments	8,392	1,868	4,833	1,691	
Seismic contracts	3,192	3,192			
Asset retirement obligations(3)	17,737				17,737
Net minimum commitments	**$ 2,852,629**	**$ 195,794**	**$ 556,383**	**$ 2,082,715**	**$ 17,737**

(1) Less than one year includes commitments from July 2015 through June 2016; 1-3 years includes commitments from July 2016 through June 2019; 3-5 years includes commitments from July 2019 through June 2021; and 5+ years includes commitments from July 2021 and beyond.

(2) Included within the interest amount shown is approximately $56.7 million in paid-in-kind interest on the Third Lien Notes that will be paid at the maturity date of June 1, 2020.

(3) Amounts represent our estimate of future asset retirement obligations on a discounted basis. Because these costs typically extend many years into the future, estimating these future costs requires management to make estimates and judgments that are subject to future revisions based upon numerous factors, including the rate of inflation, changing technology and the political and regulatory environments.

Recent Accounting Pronouncements

On May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update 2014-09, "Revenue from Contracts with Customers (Topic 606)" ("ASU 2014-09"). ASU 2014-09 provides guidance concerning the recognition and measurement of revenue from contracts with customers. The objective of ASU 2014-09 is to increase the usefulness of information in the financial statements regarding the nature, timing and uncertainty of revenues. ASU 2014-09 requires an entity to (i) identify the contract(s) with a customer, (ii) identify the performance obligations in the contract(s), (iii) determine the transaction price, (iv) allocate the transaction price to the performance obligations in the contract(s), and (v) recognize revenue when, or as, the entity satisfies a performance obligation. ASU 2014-09 will be effective for the Company beginning on January 1, 2018, including interim periods within that reporting period, considering the one year deferral approved by the FASB on July 9, 2015. The standard permits the use of either the retrospective or cumulative effect transition method. Early adoption is permitted. The Company has not selected a transition method and is evaluating the impact this standard will have on its consolidated financial statements and related disclosures.

In April 2015, the FASB issued Accounting Standards Update 2015-03, "Interest Imputation of Interest: Simplifying the Presentation of Debt Issuance Costs (Topic 835)". The update requires debt issuance costs related to a recognized debt liability be presented on the balance sheet as a direct deduction from the carrying amount of that debt liability. The standard should be applied retrospectively and is effective for the Company beginning on January 1, 2016. The Company does not believe the adoption of this guidance will have a material impact on its financial position, results of operations or cash flows.

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BUSINESS

Midstates Petroleum Company, Inc. was incorporated pursuant to the laws of the State of Delaware on October 25, 2011 to become a holding company for Midstates Sub, which was previously a wholly-owned subsidiary of Midstates Petroleum Holdings LLC. Pursuant to the terms of a corporate reorganization that was completed in connection with the closing of Midstates Petroleum Company, Inc.'s initial public offering on April 25, 2012, all of the interests in Midstates Petroleum Holdings LLC were exchanged for newly issued common shares of Midstates Petroleum Company, Inc., and as a result, Midstates Sub became a wholly-owned subsidiary of Midstates Petroleum Company, Inc. and Midstates Petroleum Holdings LLC ceased to exist as a separate entity. Our common stock, par value $0.01 per share, has been listed on the NYSE since April 2012.

On May 31, 2013, we closed on the acquisition of producing properties and undeveloped acreage in the Anadarko Basin in Texas and Oklahoma from Panther Energy Company, LLC and its partners for approximately $618 million in cash, before customary post-closing adjustments. We funded the purchase price with a portion of the net proceeds from the private placement of $700 million in aggregate principal amount of the 2021 Senior Notes, which also closed on May 31, 2013.

On May 1, 2014, we closed on the sale of all of its ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer for a purchase price of $170 million in cash, before customary post-closing adjustments. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and did not include our acreage and production in the western part of Louisiana in Beauregard and Calcasieu Parish or other undeveloped acreage held outside the Pine Prairie field.

We have oil and gas operations and properties in Oklahoma, Texas and Louisiana. At June 30, 2015, we operated oil and natural gas properties as one reportable segment engaged in the exploration, development and production of oil, natural gas liquids ("NGLs") and natural gas. Our management evaluated performance based on one reportable segment as there were not significantly different economic or operational environments within its oil and natural gas properties.

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The following table summarizes, by areas of operation, our estimated proved reserves as of December 31, 2014, their corresponding pre-tax PV-10 values and our fourth quarter 2014 average daily production rates:

	Proved Reserves(1)						Average Daily Production for Three Months Ended December 31, 2014
	Oil (MBbl)	NGL (MBbl)	Gas (MMcf)	Total(2) (MBoe)	% Oil(4)	PV-10(3) (in thousands)	(Boe/day)
Areas of Operation							
Mississippian	51,494	28,957	350,064	138,796	58%	$ 2,055,345	25,039
Anadarko Basin	4,963	3,011	26,176	12,336	65%	262,705	7,337
Gulf Coast	1,785	560	1,605	2,612	90%	68,336	1,388
Total	**58,242**	**32,528**	**377,845**	**153,744**	**59%**	**$ 2,386,386**	**33,764**
Discounted Future Income Taxes						(513,025)	
Standardized Measure of Discounted Future Net Cash Flows						**$ 1,873,361**	

(1) Oil, natural gas liquids and natural gas reserve quantities and related discounted future net cash flows have been derived from oil, natural gas liquids and natural gas prices calculated using an average of the first-day-of-the month price for each month within the 12 months ended December 31, 2014, pursuant to current SEC and FASB guidelines and were $94.99/Bbl for oil, $39.17/Bbl for NGLs and $4.35 per MMBtu for natural gas.

(2) Barrel of oil equivalents are determined using a ratio of one Bbl of crude to six Mcf of natural gas, which represents their approximate relative energy content.

(3) Pre-tax PV-10 may be considered a non-GAAP financial measure as defined by the SEC and is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. Pre-tax PV-10 is computed on the same basis as the standardized measure of discounted future net cash flows but without deducting future income taxes. We believe pre-tax PV-10 is a useful measure for investors for evaluating the relative monetary significance of our oil and natural gas properties. We further believe investors may utilize our pre-tax PV-10 as a basis for comparison of the relative size and value of our proved reserves to other companies because many factors that are unique to each individual company impact the amount of future income taxes to be paid. Our management uses this measure when assessing the potential return on investment related to our oil and natural gas properties and acquisitions. However, pre-tax PV-10 is not a substitute for the standardized measure of discounted future net cash flows. Our pre-tax PV-10 does not purport to present the fair value of our proved oil and natural gas reserves.

(4) Includes volumes attributable to oil and NGLs.

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During 2014, we incurred the following operational and total capital expenditures (in thousands):

	For the Twelve Months Ended December 31, 2014
Drilling and completion activities	$ 511,295
Acquisition of acreage and seismic data	19,150
Operational capital expenditures incurred	**$ 530,445**
Capitalized G&A, office, ARO & other	12,081
Capitalized interest	12,414
Total capital expenditures incurred	**$ 554,940**

As noted above, we incurred operational capital expenditures of $530.4 million during the year ended December 31, 2014, of which $383.2 million was spent in the Mississippian Lime, $139.8 million was spent in the Anadarko Basin and $7.4 million was spent in the Gulf Coast area. We expect to invest between $250 million and $275 million of capital for exploration, development and lease and seismic acquisition in 2015. Additionally, we expect to capitalize between $4 million and $6 million of interest expense. Furthermore, we incurred operational capital expenditures of $163.3 million during the six months ended June 30, 2015, of which $156.6 million was spent in the Mississippian Lime, $4.7 million was spent in the Anadarko Basin and $2.1 million was spent in the Gulf Coast area.

Strategies

Our goal is to grow our reserves, production and cash flows at an attractive rate of return on invested capital. To achieve these objectives, we strive to:

- Operate in a safe and environmentally responsible manner;
- Allocate capital to projects that generate the highest returns;
- Maintain a sustainable, diverse inventory of low-cost, high-margin resource plays;
- Drill in the highest potential areas of the resource plays in which we operate;
- Build contiguous acreage positions that drive operating efficiencies;
- Be the operator of our assets, whenever possible;
- Be the low-cost driller and producer in each area where we operate;
- Utilize derivative contracts to mitigate the impact of oil, NGL or natural gas price volatility, while locking in acceptable cash flows required to support future capital expenditures; and
- Attract and retain the best people.

Development of our multi-year drilling inventory. We intend to drill and develop our current acreage position to maximize the value of our primarily oil and liquids rich resource potential from resource plays in our core areas of operation where we can capitalize on our operating expertise. For 2015, we plan to allocate substantially all of our drilling and completions capital budget to development activities in the Mississippian area, based on the relatively stronger economic returns expected from these assets in the current commodity price and cost environment.

Mississippian. Our Mississippian assets acquired on October 1, 2012 are located in Oklahoma and target the Mississippian Lime and Hunton formations. The Mississippian Lime is an expansive carbonate hydrocarbon system located in the Anadarko Basin, primarily in northern Oklahoma. We currently intend to continue development of these liquids rich properties using

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horizontal wells and multi-stage frac technology. The Hunton formation is a limestone formation that produces primarily natural gas from our acreage in Lincoln County, Oklahoma. Because the Hunton targets primarily natural gas, our capital deployment will be focused on the Mississippian Lime until natural gas prices demonstrate sustained improvement from recent levels. At December 31, 2014, we had approximately 99,100 gross (79,000 net) acres under lease in the area, comprised of approximately 78,100 gross (66,300 net) leased acres in the Mississippian Lime and approximately 21,000 gross (12,700 net) acres in the Hunton. As of June 30, 2015, we had four drilling rigs in operation. We expect to spud between 58 to 64 gross (46 to 52 net) horizontal wells, including non-operated wells, during 2015 on this acreage.

Anadarko Basin. Our Anadarko Basin assets acquired on May 31, 2013 are located in Western Oklahoma and Texas and target multiple objectives in the Pennsylvanian section. We target the Cleveland, Marmaton, Cottage Grove and Tonkawa formations in the Anadarko Basin by utilizing horizontal wells and multi-stage frac technology. At December 31, 2014, we had approximately 161,500 gross (122,600 net) acres under lease in the Anadarko Basin, comprised of approximately 44,100 gross (32,300 net) leased acres in Oklahoma and approximately 117,400 gross (90,300 net) acres in the Texas. As of June 30, 2015, we did not have any drilling rigs in operation in this area. In the current price environment, we do not expect to spud any wells on this acreage during 2015. We intend to continue to evaluate this prospective acreage for future drilling plans if commodity prices continue to decline and/or drilling and completion costs experience sustained improvement.

Gulf Coast. At December 31, 2014 we had approximately 68,200 gross (50,600 net) acres under lease and/or lease option. On March 5, 2014, we executed a Purchase and Sale Agreement ("PSA") to sell all of our ownership interest in developed and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana to a private buyer. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres and closed on May 1, 2014. On June 25, 2014, we entered into an exploration agreement with PetroQuest Energy ("PetroQuest") to sell 50% of our ownership interest in the Fleetwood prospect area in Louisiana. During 2015, we plan to participate with PetroQuest and other owners in the joint exploration and development of the Fleetwood area in Iberville, Point Coupee, and West Baton Rouge Parish, Louisiana. We executed a PSA in March 2015 for the sale of our Dequincy assets, our only remaining producing properties in Louisiana, for total consideration of $44 million (subject to customary purchase price adjustments). The PSA includes our ownership interest in developed and undeveloped acreage totaling approximately 12,700 net mineral acres in the Dequincy area. During the fourth quarter 2014, the properties produced approximately 1,300 Boe per day. The transaction does not include our acreage and interests in the Fleetwood area of Louisiana. The net proceeds from the sale will be used to pay down a portion of the outstanding borrowings under our revolving credit facility and for general corporate purposes. The transaction had an effective date of March 1, 2015 and closed on April 21, 2015, subject to customary closing conditions. In the last year, we have shifted capital from the Gulf Coast area and as of June 30, 2015 we did not have any operated rigs active in the area. Our intent is to continue high grading inventory in Louisiana for future capital deployment. Other than the Fleetwood project, we expect limited development activity in the Gulf Coast area in 2015 as we continue focusing on the development of our Mississippian assets.

Maintain operatorship across a diverse asset base. Our diverse set of assets and high degree of operating control, facilitated by our position as operator on the majority of our properties, provide flexibility with respect to drilling and completion techniques and the timing and amount of capital expenditures that support growth and help us meet our targeted financial profile.

Utilize our technical and operating expertise to enhance returns. Our technical teams are focused on the application of modern reservoir evaluation and drilling and completion techniques to reduce risk and enhance returns in our core areas. We utilize 2D, 3D and micro seismic data, existing sub-surface well control data, detailed reservoir characterization and geologic and geochemical modeling to identify areas with significant exploration and development potential. These areas become targets for our leasing activity. Once we have identified a potential target, we attempt to maximize returns by applying modern drilling and completion techniques that maximize recoveries in a cost efficient and economically attractive manner. We utilize reservoir evaluation methods such as conventional and rotary sidewall coring, pressure sampling and other reservoir description techniques to better understand the ultimate potential of a particular area. We believe future development across our acreage position can be further optimized with specialized completion techniques, infill drilling, horizontal wellbore optimization and enhanced recovery methods.

Selectively increase our acreage position. While we believe our existing acreage positions provide significant growth opportunities, we continue to strategically increase our leasehold position in what we believe are the most prospective areas of our acreage. We believe our current Oklahoma and Texas acreage is highly prospective in the Pennsylvanian and Mississippian Lime sections and may be prospective in both shallower and deeper geologic sections.

Apply rigorous investment analysis to capital allocation decisions. We employ rigorous investment analysis to determine the allocation of capital across our many drilling opportunities and in evaluating potential acquisitions. We are focused on maximizing the internal rate of return on our investment capital and screen drilling opportunities and acquisition opportunities by measuring risk and financial return, among other factors. We continually evaluate our inventory of potential investments by these measures, incorporating past drilling results, historical knowledge and new information we have gathered.

Extensive technical knowledge in our areas of operations. In our Mississippian Lime area, we believe our team's early experience operating in this trend gives us a competitive advantage with respect to geological understanding, drilling and completion techniques and infrastructure development. In the Anadarko Basin area, that we have a history of drilling horizontally in several of the Pennsylvanian sands since 2005. We have had operations in the Upper Gulf Coast Tertiary trend since 1993. We believe our extensive operating experience in the trend provides us with an expansive technical understanding and ability to optimize production from these properties. We believe we have developed amicable and mutually beneficial relationships with acreage owners in all of our core operating areas, which we believe also provides us with a competitive advantage with respect to our leasing and development activity. We also benefit from long-term relationships with local service companies and infrastructure providers that we believe contribute to our efficient low-cost operations.

Summary of Oil and Gas Properties and Operations

Mississippian Lime

At December 31, 2014, our Mississippian Lime assets consisted of approximately 66,300 net prospective acres in the Mississippian Lime trend, with 64,100 net acres in Woods and Alfalfa Counties of Oklahoma, which we currently believe is the core of the trend. We currently intend to develop these liquids-rich properties using horizontal wells. We also own approximately 12,700 net acres in Lincoln County, Oklahoma, which produces from, and is prospective in, the Hunton formation.

Our properties in this area represented 90% of our total proved reserves as of December 31, 2014. As of December 31, 2014, we held an average working interest and average net revenue interest of 69% and 55%, respectively, in this area.

For the years ended December 31, 2014 and 2013, our average daily production from this area was as follows:

	Years Ended December 31,		
	2014	2013	Increase in Production
Average daily production:			
Oil (Bbls)	8,411	4,567	84%
Natural gas liquids (Bbls)	4,437	2,620	69%
Natural gas (Mcf)	52,024	34,784	50%
Net Boe/day	21,518	12,985	66%

During 2014, we invested approximately $383.2 million and spud 76 net horizontal wells in this region. Of the 16 net wells spud during the last quarter of 2014, three were drilling, 10 were awaiting completion and three were producing at year-end

Our main operating area in the Mississippian Lime is defined by de-risked acreage primarily in Woods County, where we are engaged in development drilling. Our current development drilling is targeting the Mississippian Lime interval, where we anticipate ultimate development of at least four horizontal wells per 640 acre section. We are also testing different drilling and completion techniques to determine the most cost effective design in this area.

In 2015, we plan to invest approximately $250 million to $275 million in the spudding of between 58 to 64 gross wells, including non-operated wells. Our plans are to continue to actively develop this area while evaluating exploration potential beyond our current position.

Expansion Areas within Mississippian Lime

The majority of our rigs currently operating in the Mississippian Lime are focused on infill drilling in our core area; during 2015, we plan to drill four to six wells to extend our de-risked acreage to the west and hold acreage.

Anadarko Basin

Our Anadarko Basin assets were acquired on May 31, 2013, and at December 31, 2014, consisted of approximately 122,600 net acres in the Anadarko Basin, with 90,300 net acres in Texas and 32,300 net acres in western Oklahoma. We took over operation of the properties on December 1, 2013. As of December 31, 2014, we did not have any drilling rigs in operation in this area.

Our properties in this area represented 8% of our total proved reserves as of December 31, 2014. As of December 31, 2014, we held an average working interest and average net revenue interest of 66% and 52%, respectively, in this area.

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For the years ended December 31, 2014 and 2013, our average daily production from this area was as follows:

	Years Ended December 31,		
	2014	2013(1)	Increase in Production
Average daily production:			
Oil (Bbls)	4,014	2,239	79%
Natural gas liquids (Bbls)	1,766	1,082	63%
Natural gas (Mcf)	14,930	9,559	56%
Net Boe/day	8,269	4,914	68%

(1) Note that as the Anadarko Basin Acquisition closed on May 31, 2013, this represents the impact to average annual production for the period of May 31, 2013 through December 31, 2013.

During 2014, we invested approximately $139.8 million and spud 26 net horizontal wells in the area. Of the three net wells spud during the last quarter of 2014, two were awaiting completion and one was producing at year-end. Since year-end, three wells have been completed and brought online.

In the current commodity price and drilling and completion cost environment, we do not currently plan to spud any wells on this acreage during 2015, however we will continue to evaluate for opportunities. For 2015, our efforts will focus on reducing well maintenance costs and production downtime and these efforts alone will not be sufficient to arrest the natural decline in production that occurs as we deplete our developed reserves. Additionally, because of our limited capital resources, we may allow leasehold rights on acreage not held by production to expire, which could reduce our future drilling opportunities in this area.

Gulf Coast

In the Gulf Coast, our current acreage positions and evaluation efforts are concentrated in Louisiana in the Wilcox interval of the Upper Gulf Coast Tertiary trend and is characterized by well-defined geology, including tight sands featuring multiple productive zones typically located within large geologic traps. As of December 31, 2014, we had, including acreage in the Fleetwood area, approximately 50,600 net acres in the trend under lease and/or lease option.

We closed on the sale of producing properties and undeveloped acreage in the Pine Prairie field area of Evangeline Parish, Louisiana on May 1, 2014 for estimated net proceeds of $147.5 million in cash, after post-closing adjustments. The sale has an effective date of November 1, 2013. Acreage subject to the transaction totaled 3,907 gross (3,757 net) acres, and did not include our acreage and production in the western part of Louisiana in Beauregard Parish or other undeveloped acreage held outside the Pine Prairie field. Production from the assets included in this sale averaged 626 and 3,453 Boe/d during the years ended December 31, 2014 and 2013, respectively, and 2,366 Boe/d during the quarter ended December 31, 2013. There was no production from Pine Prairie during the quarter ended December 31, 2014. Our remaining Gulf Coast areas of operation are concentrated in the South Bearhead and North Coward's Gully fields.

On June 25, 2014, we entered into an exploration agreement with PetroQuest to sell 50% of our ownership interest in the Fleetwood prospect area in Louisiana. We plan to participate with PetroQuest and other owners in the joint exploration and development of the Fleetwood area in Iberville, Point Coupee, and West Baton Rouge Parish, Louisiana. There are currently three wells planned to be spud in the first six months of the year; we will have a carried working interest ranging from 25% to 50% in those wells. The carried working interest is capped at a total credit of $14 million.