

COMSTOCK RESOURCES INC
Form 10-K
February 26, 2016

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

(Mark One)

ANNUAL REPORT PURSUANT TO SECTION 13 OR
15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2015

OR

TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF
THE SECURITIES EXCHANGE ACT OF 1934
For the transition period from _____ to _____

Commission File No. 001-03262

COMSTOCK RESOURCES, INC.

(Exact name of registrant as specified in its charter)

NEVADA 94-1667468
(State or other jurisdiction of (I.R.S. Employer

incorporation or organization) Identification Number)
5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034

(Address of principal executive offices including zip code)

(972) 668-8800

(Registrant's telephone number and area code)

Securities registered pursuant to Section 12(b) of the Act:

Common Stock, \$.50 Par Value	New York Stock Exchange
(Title of class)	(Name of exchange on which registered)

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Securities registered pursuant to Section 12(g) of the Act:

None

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act.

Yes No

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act.

Yes No

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days.

Yes No

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§ 232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files).

Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Exchange Act Rule 12b-2).

Yes No

The aggregate market value of the common stock held by non-affiliates of the registrant, based on the closing price of common stock on the New York Stock Exchange on June 30, 2015 (the last business day of the registrant's most recently completed second fiscal quarter), was \$145.4 million.

As of February 26, 2016, there were 53,178,316 shares of common stock of the registrant outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the Definitive Proxy Statement for the 2016 Annual Meeting of Stockholders

are incorporated by reference into Part III of this report.

COMSTOCK RESOURCES, INC.

ANNUAL REPORT ON FORM 10-K

For the Fiscal Year Ended December 31, 2015

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CAUTIONARY NOTE REGARDING FORWARD-LOOKING STATEMENTS

The information contained in this report includes "forward-looking statements" within the meaning of Section 27A of the Securities Act of 1933 and Section 21E of the Securities Exchange Act of 1934. These forward-looking statements are identified by their use of terms such as "expect," "estimate," "anticipate," "project," "plan," "intend," "believe" and similar terms. All statements, other than statements of historical facts, included in this report, are forward-looking statements, including statements mentioned under "Risk Factors" and "Management's Discussion and Analysis of Financial Condition and Results of Operations," regarding:

- amount and timing of future production of oil and natural gas;
- amount, nature and timing of capital expenditures;
- the number of anticipated wells to be drilled after the date hereof;
- the availability of exploration and development opportunities;
- our financial or operating results;
- our cash flow and anticipated liquidity;
 - operating costs including lease operating expenses, administrative costs and other expenses;
- finding and development costs;
- our business strategy; and
- other plans and objectives for future operations.

Any or all of our forward-looking statements in this report may turn out to be incorrect. They can be affected by a number of factors, including, among others:

- the risks described in "Risk Factors" and elsewhere in this report;
- the volatility of prices and supply of, and demand for, oil and natural gas;
- the timing and success of our drilling activities;
- the numerous uncertainties inherent in estimating quantities of oil and natural gas reserves and actual future production rates and associated costs;
- our ability to successfully identify, execute or effectively integrate future acquisitions;
- the usual hazards associated with the oil and natural gas industry, including fires, well blowouts, pipe failure, spills, explosions and other unforeseen hazards;
- our ability to effectively market our oil and natural gas;
- the availability of rigs, equipment, supplies and personnel;
- our ability to discover or acquire additional reserves;
- our ability to satisfy future capital requirements;
- changes in regulatory requirements;
- general economic conditions, status of the financial markets and competitive conditions; and
 - our ability to retain key members of our senior management and key employees.

DEFINITIONS

The following are abbreviations and definitions of terms commonly used in the oil and gas industry and this report. Natural gas equivalents and crude oil equivalents are determined using the ratio of six Mcf to one barrel. All references to "us", "our", "we" or "Comstock" mean the registrant, Comstock Resources, Inc. and where applicable, its consolidated subsidiaries.

"Bbl" means a barrel of U.S. 42 gallons of oil.

"Bcf" means one billion cubic feet of natural gas.

"Bcfe" means one billion cubic feet of natural gas equivalent.

"BOE" means one barrel of oil equivalent.

"Btu" means British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water from 58.5 to 59.5 degrees Fahrenheit.

"Completion" means the installation of permanent equipment for the production of oil or gas.

"Condensate" means a hydrocarbon mixture that becomes liquid and separates from natural gas when the gas is produced and is similar to crude oil.

"Development well" means a well drilled within the proved area of an oil or gas reservoir to the depth of a stratigraphic horizon known to be productive.

"Dry hole" means a well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceed production expenses and taxes.

"Exploratory well" means a well drilled to find and produce oil or natural gas reserves not classified as proved, to find a new productive reservoir in a field previously found to be productive of oil or natural gas in another reservoir or to extend a known reservoir.

"GAAP" means generally accepted accounting principles in the United States of America.

"Gross" when used with respect to acres or wells, production or reserves refers to the total acres or wells in which we or another specified person has a working interest.

"MBbls" means one thousand barrels of oil.

"MBbls/d" means one thousand barrels of oil per day.

"Mcf" means one thousand cubic feet of natural gas.

"Mcfe" means one thousand cubic feet of natural gas equivalent.

"MMBbls" means one million barrels of oil.

"MMBOE" means one million barrels of oil equivalent.

"MMBtu" means one million British thermal units.

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"MMcf" means one million cubic feet of natural gas.

"MMcf/d" means one million cubic feet of natural gas per day.

"MMcfe/d" means one million cubic feet of natural gas equivalent per day.

"MMcfe" means one million cubic feet of natural gas equivalent.

"Net" when used with respect to acres or wells, refers to gross acres of wells multiplied, in each case, by the percentage working interest owned by us.

"Net production" means production we own less royalties and production due others.

"Oil" means crude oil or condensate.

"Operator" means the individual or company responsible for the exploration, development, and production of an oil or gas well or lease.

"Proved developed reserves" means reserves that can be expected to be recovered through existing wells with existing equipment and operating methods.

"Proved developed non-producing" means reserves (i) expected to be recovered from zones capable of producing but which are shut-in because no market outlet exists at the present time or whose date of connection to a pipeline is uncertain or (ii) currently behind the pipe in existing wells, which are considered proved by virtue of successful testing or production of offsetting wells.

"Proved developed producing" means reserves expected to be recovered from currently producing zones under continuation of present operating methods. This category includes recently completed shut-in gas wells scheduled for connection to a pipeline in the near future.

"Proved reserves" means the estimated quantities of crude oil, natural gas, and natural gas liquids which geological and engineering data demonstrate with reasonable certainty to be recoverable in future years from known reservoirs under existing economic and operating conditions, i.e., prices and costs as of the date the estimate is made. Prices include consideration of changes in existing prices provided by contractual arrangements.

"Proved undeveloped reserves" means 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. Reserves on undrilled acreage are limited to those drilling locations offsetting productive wells that are reasonably certain of production when drilled or where it can be demonstrated with certainty that there is continuity of production from the existing productive formation.

"Recompletion" means the completion for production of an existing well bore in another formation from which the well has been previously completed.

"Reserve life" means the calculation derived by dividing year-end reserves by total production in that year.

"Reserve replacement" means the calculation derived by dividing additions to reserves from acquisitions, extensions, discoveries and revisions of previous estimates in a year by total production in that year.

"Royalty" means an interest in an oil and gas lease that gives the owner of the interest the right to receive a portion of the production from the leased acreage (or of the proceeds of the sale thereof), but generally does not require the owner to pay any portion of the costs of drilling or operating the wells on the leased acreage. Royalties may be either landowner's royalties, which are reserved by the owner of the leased acreage at the time the lease is granted, or overriding royalties, which are usually reserved by an owner of the leasehold in connection with a transfer to a subsequent owner.

"3-D seismic" means an advanced technology method of detecting accumulations of hydrocarbons identified by the collection and measurement of the intensity and timing of sound waves transmitted into the earth as they reflect back to the surface.

"SEC" means the United States Securities and Exchange Commission.

"Tcfe" means one trillion cubic feet of natural gas equivalent.

"Working interest" means an interest in an oil and gas lease that gives the owner of the interest the right to drill for and produce oil and gas on the leased acreage and requires the owner to pay a share of the costs of drilling and production operations. The share of production to which a working interest owner is entitled will always be smaller than the share of costs that the working interest owner is required to bear, with the balance of the production accruing to the owners of royalties. For example, the owner of a 100% working interest in a lease burdened only by a landowner's royalty of 12.5% would be required to pay 100% of the costs of a well but would be entitled to retain 87.5% of the production.

"Workover" means operations on a producing well to restore or increase production.

PART I

ITEMS 1 and 2. BUSINESS AND PROPERTIES

We are engaged in the acquisition, development, production and exploration of oil and natural gas. Our common stock is listed and traded on the New York Stock Exchange.

Our oil and gas operations are concentrated in Texas and Louisiana. Our oil and natural gas properties are estimated to have proved reserves of 625 Bcfe with a standardized measure of discounted future net cash flows of \$372.1 million as of December 31, 2015. Our proved oil and natural gas reserve base is 91% natural gas and 9% oil and was 59% developed as of December 31, 2015.

Our proved reserves at December 31, 2015 and our 2015 average daily production are summarized below:

	Proved Reserves at December 31, 2015				2015 Average Daily Production			
	Natural Oil (MMbbl/d)	Gas (Bcf)	Total (Bcfe)	% of Total	Natural Oil (MMbbl/d)	Gas (MMcfe/d)	Total (MMcfe/d)	% of Total
East Texas / North Louisiana	0.3	493.6	495.4	79.3 %	0.2	106.9	107.9	59.5 %
South Texas	8.8	67.3	119.9	19.2 %	8.1	20.3	68.9	38.0 %
Other Regions	0.1	8.7	9.7	1.5 %	0.2	3.4	4.6	2.5 %
Total	9.2	569.6	625.0	100.0%	8.5	130.6	181.4	100.0%

Strengths

High Quality Properties. Our operations are focused in two operating areas: East Texas/North Louisiana and South Texas. Our properties have an average reserve life of approximately 9.4 years and have extensive development and exploration potential. Our properties in the East Texas/North Louisiana region, which are primarily prospective for natural gas, include 80,657 acres (68,331 net to us) in the Haynesville or Bossier shale formations. Advances in drilling and completion technology have allowed us to increase the reserves recovered through longer horizontal lateral length and substantially larger well stimulation. As a result of the improved economic returns that we achieved with our Haynesville shale natural gas wells, and the continuing decline of oil prices, our 2015 drilling activity primarily targeted natural gas in the Haynesville shale. In our South Texas region, our Eagleville field includes

30,219 acres (22,246 net to us) located in the oil window of the Eagle Ford shale. Our oil development program in the Eagleville field in 2015 was limited to the completion of wells that were drilled in 2014. In addition to our acreage in the Eagle Ford shale, we have 87,746 acres (81,537 net to us) in Mississippi and Louisiana that are prospective for oil development in the Tuscaloosa Marine shale. We did not drill on these properties in 2015 due to the low oil prices throughout the year, and we have extended lease terms on key acreage in this area to hold this oil acreage until prices support further development.

Successful Exploration and Development Program. In 2015, we spent \$227.7 million on exploration and development activities, of which \$196.4 million was for drilling and completing wells. We drilled 15 wells (13.6 net to us) and completed 23 wells (19.6 net to us). We also spent \$13.7 million in 2015 on leasehold costs and \$31.3 million for other development costs. Of our 2015 capital expenditures, 48% was directed towards natural gas projects. In 2015, our natural gas drilling program grew our natural gas production by 20% over 2014 and increased our proved natural gas reserves by 167 Bcf.

Efficient Operator. We operated 98% of our proved reserve base as of December 31, 2015. As the operator, we are better able to control operating costs, the timing and plans for future development, the level of drilling and lifting costs and the marketing of production. As an operator, we receive reimbursements for overhead from other working interest owners, which reduces our general and administrative expenses.

Successful Acquisitions. We have had significant growth over the years as a result of our acquisition activity. In recent years, we have focused primarily on acquiring undrilled acreage rather than producing properties. We apply strict economic and reserve risk criteria in evaluating acquisitions. Over the past 25 years, we have added 1.1 Tcfe of proved oil and natural gas reserves from 38 acquisitions of producing oil and gas properties at an average cost of \$1.17 per Mcfe. Our application of strict economic and reserve risk criteria have enabled us to successfully evaluate and integrate acquisitions.

Business Strategy

Pursue Exploration Opportunities. Each year, we conduct exploration activities to grow our reserve base and to replace our production. In 2015, we focused on natural gas development as our natural gas projects in the Haynesville and Bossier shales provide us the highest returns within our opportunity set. We deferred further development of our oil properties under the low oil price environment.

In 2015, our Haynesville shale properties were the primary focus of our drilling activity. We have 80,657 acres (68,331 net to us) in East Texas and North Louisiana with Haynesville or Bossier shale natural gas potential. In January 2016, we completed an acreage swap with another operator which increased our Haynesville shale properties by 3,637 net acres in DeSoto Parish, Louisiana. Our 2015 drilling program focused on natural gas development based on a new well design that significantly enhanced the economics of these wells. We spent \$109.9 million to drill 10 wells (9.6 net to us) on our Haynesville and Bossier shale properties and to recomplete two wells using the new enhanced completion design. We expect to spend approximately \$89.9 million in 2016 to drill nine horizontal natural gas wells on our Haynesville shale properties.

From 2010 through 2015, we spent approximately \$169.5 million leasing acreage in South Texas, in the oil window of the Eagle Ford shale formation. We have in place a joint venture which allows us to accelerate the development of this field. Our joint venture partner participates for a one-third interest in the wells that we drill in exchange for paying \$25,000 per net acre that is earned by its participation. Through December 31, 2015, we have drilled 196 wells (138.2 net to us) in our Eagleville field. Our joint venture partner participated in 144 of these wells and contributed \$86.0 million through 2015 for acreage and an additional \$9.1 million to reimburse us for a portion of common production facilities. During 2015, we completed four oil wells that were drilled on these properties during 2014, but we did not drill any new wells in 2015 and we are not currently anticipating any drilling activity on our oil properties until oil prices improve. In January 2016, we exchanged 2,547 net acres in Atascosa County, Texas for Haynesville shale acreage.

We divested all of our acreage in or near Burleson County, Texas in 2015 which were prospective for oil in the Eagle Ford shale formation. Cash proceeds realized from this sale were \$102.5 million. We spent \$69.1 million to drill four wells (4.0 net to us) and to complete eight wells (7.8 net to us) on this acreage in 2015 prior to their sale.

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Through the end of 2015 we spent \$94.2 million to acquire 87,746 acres (81,537 net to us) in Louisiana and Mississippi which are prospective for oil in the Tuscaloosa Marine shale. During 2014 we drilled our first well on this acreage but did not drill any wells in 2015 due to the decline in oil prices. We are not currently anticipating any drilling activity on this acreage during 2016 until oil prices improve. The lease terms on our key acreage in this area were modified during 2015 to allow us to defer drilling activity until 2018.

Enhance Liquidity and Reduce Leverage. With the substantial decline in oil and natural gas prices we experienced in 2015, which have continued into 2016, we have taken several steps to enhance liquidity, reduce corporate commitments and ultimately reduce our leverage. In late 2014 and into 2015 we reduced our drilling activity and released three operated drilling rigs. We substantially reduced our capital spending in 2015 and are further reducing activity in 2016 as oil and natural gas prices have declined further. In March 2015, we refinanced our bank revolving credit facility with \$700 million of senior secured notes which mature in 2020. The bank credit facility was subject to a semi-annual borrowing base which was based on current oil and gas prices. During 2015, we repurchased \$129.5 million in principal amount of our senior notes for an aggregate purchase price of \$42.7 million. The repurchases reduced our annual interest expense by \$11.9 million. In February 2016 we repurchased an additional \$40.0 million in principal amount of our senior notes through the issuance of 4.6 million shares of our common stock. We plan to continue pursuing strategies to allow us to retire additional debt in 2016.

Exploit Existing Reserves. We seek to maximize the value of our oil and gas properties by increasing production and recoverable reserves through development drilling and workover, recompletion and exploitation activities. We utilize advanced industry technology, including 3-D seismic data, horizontal drilling, enhanced logging tools, and formation stimulation techniques. We spent \$4.6 million in 2015 to refrac two of our producing horizontal wells in the Haynesville shale. This pilot program was successful in enhancing production from these wells by 577%. The success of this program supports a future program to re-stimulate many of our 186 producing natural gas shale wells and may also have applicability to our 196 horizontal oil shale wells when well economics support these investments.

Maintain Flexible Capital Expenditure Budget. The timing of most of our capital expenditures is discretionary because we have not made any significant long-term capital expenditure commitments. We operate most of the drilling projects in which we participate. Consequently, we have a significant degree of flexibility to adjust the level of such expenditures according to market conditions. For 2016 we have one operated drilling rig under contract and plan to drill up to nine wells. We expect to spend approximately \$98.0 million in 2016 on our development and exploration projects. We do not have any contractual requirements to drill more than three wells and could reduce the number of wells drilled in 2016 based on industry conditions.

Acquire High Quality Properties at Attractive Costs. Historically, we have had a successful track record of increasing our oil and natural gas reserves through opportunistic acquisitions. Over the past 25 years, we have added 1.1 Tcfe of proved oil and natural gas reserves from 38 acquisitions of producing oil and gas properties at a total cost of \$1.3 billion, or \$1.17 per Mcfe. In evaluating acquisitions, we apply strict economic and reserve risk criteria. We target properties in our core operating areas with established production and low operating costs that also have potential opportunities to increase production and reserves through exploration and exploitation activities.

Primary Operating Areas

The following table summarizes the estimated proved oil and natural gas reserves for our ten largest fields as of December 31, 2015:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe) ⁽¹⁾	%
East Texas / North Louisiana:				
Logansport	18	422,504	422,614	67.6 %
Beckville	105	23,923	24,551	3.9 %
Toledo Bend	—	18,796	18,796	3.0 %
Waskom	48	8,642	8,931	1.4 %
Blocker	29	6,707	6,881	1.1 %
Other	101	13,062	13,667	2.3 %
	301	493,634	495,440	79.3 %
South Texas:				
Eagleville	8,701	9,119	61,327	9.8 %
Fandango	—	27,487	27,487	4.4 %
Rosita	—	20,258	20,258	3.2 %
Javelina	35	4,251	4,459	0.7 %
Las Hermanitas	—	3,210	3,210	0.5 %
Other	35	2,998	3,207	0.6 %
	8,771	67,323	119,948	19.2 %
Other	157	8,639	9,583	1.5 %
Total	9,229	569,596	624,971	100.0%

(1) Oil is converted to natural gas equivalents by using a conversion factor of one barrel of oil for six Mcf of natural gas based upon the approximate relative energy content of oil to natural gas, which is not indicative of oil and natural gas prices.

East Texas/North Louisiana Region

Approximately 79%, or 495.4 Bcfe of our proved reserves are located in East Texas and North Louisiana where we own interests in 921 producing wells (573.0 net to us) in 28 field areas. We operate 644 of these wells. The largest of our fields in this region are the Logansport, Beckville, Toledo Bend, Waskom and Blocker fields. Production from this region averaged 107 MMcf of natural gas per day and 158 barrels of oil per day during 2015 or 108 MMcfe per day. Most of the reserves in this area produce from the upper Jurassic aged Haynesville or Bossier shale or Cotton Valley formations and the Cretaceous aged Travis Peak/Hosston formation. In 2015, we spent \$109.9 million drilling ten wells (9.6 net to us), \$1.4 million on other development and \$0.8 million on leasehold costs in this region. We plan to

spend approximately \$89.9 million in 2016 to drill nine Haynesville/Bossier shale natural gas wells.

Logansport

The Logansport field located in DeSoto Parish, Louisiana primarily produces from the Haynesville and Bossier shale formations at a depth of 11,100 to 11,500 feet and from multiple sands in the Cotton Valley and Hosston formations at an average depth of 8,000 feet. Our proved reserves of 422.6 Bcfe in the Logansport field represent approximately 68% of our proved reserves. We own interests in 250 wells (168.7 net to us) and operate 182 of these wells in this field. In 2015 we drilled nine wells (8.6 net to us) in the Logansport field. Our 2016 drilling program will be focused primarily on drilling additional horizontal wells in Logansport targeting the Haynesville shale formation each with a planned lateral length of 7,500 to 10,000 feet.

Beckville

The Beckville field, located in Panola and Rusk Counties, Texas, has estimated proved reserves of 24.6 Bcfe which represents approximately 4% of our proved reserves. We operate 187 wells in this field and own interests in 72 additional wells for a total of 259 wells (156.2 net to us). The Beckville field produces primarily from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet. The field is also prospective for future Haynesville shale development.

Toledo Bend

The Toledo Bend field, located in DeSoto and Sabine Parishes in Louisiana, is productive in the Haynesville shale from 11,400 to 11,800 feet and in the Bossier shale from 10,880 to 11,300 feet. Our proved reserves of 18.8 Bcfe in the Toledo Bend field represent approximately 3% of our reserves. We own interests in 76 producing wells (39.3 net to us) and operate 41 of these wells in this field. During 2015 we drilled one well (0.9 net to us) in the Toledo Bend field.

Waskom

The Waskom field, located in Harrison and Panola Counties in Texas, represents approximately 1% (8.9 Bcfe) of our proved reserves. We own interests in 59 wells (35.5 net to us) and operate 43 wells in this field. The Waskom field produces from the Cotton Valley formation at depths ranging from 9,000 to 10,000 feet and from the Haynesville shale formation at depths of 10,800 to 10,900 feet.

Blocker

Our proved reserves of 6.9 Bcfe in the Blocker field located in Harrison County, Texas represent approximately 1% of our proved reserves. We own interests in 74 wells (68.4 net to us) and operate 69 of these wells. Most of this production is from the Cotton Valley formation between 8,600 and 10,150 feet and the Haynesville shale formation between 11,100 and 11,450 feet.

South Texas Region

Approximately 19%, or 20.0 MMBOE (119.9 Bcfe), of our proved reserves are located in South Texas, where we own interests in 322 producing wells (208.2 net to us). We own interests in 13 field areas in the region, the largest of which are the Eagleville, Fandango, Rosita, Javelina and Las Hermanitas fields. Net daily production rates from this region averaged 8,105 barrels of oil and 20 MMcf of natural gas during 2015 or 11,485 BOE per day. We have no current plans to drill or recomplete wells in South Texas during 2016 due to the continued low oil price environment.

Eagleville

We have 30,219 acres (22,246 net to us) in McMullen, Atascosa, Frio, La Salle, Karnes and Wilson Counties which comprise our Eagleville field. The Eagle Ford shale is found between 7,500 feet and 11,500 feet across our acreage position. At December 31, 2015 we had 196 wells (138.1 net to us) producing in the Eagleville field. Our proved reserves in this field are estimated to be 10.2 MMBOE (61.3 Bcfe) (85% oil) and represent 10% of our total proved reserves. We spent \$17.4 million in 2015 to complete four oil wells (4.0 net to us) and \$24.2 million for other development activity in Eagleville.

Fandango

We own interests in 17 wells (17.0 net to us) in the Fandango field located in Zapata County, Texas. We operate all of these wells which produce from the Wilcox formation at depths from approximately 13,000 to 18,000 feet. Our proved reserves of 27.5 Bcfe in this field represent approximately 4% of our total proved reserves.

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Rosita

We own interests in 24 wells (13.2 net to us) in the Rosita field, located in Duval County, Texas. We operate 23 of these wells which produce from the Wilcox formation at depths from approximately 9,300 to 17,000 feet. Our proved reserves of 20.3 Bcfe in this field represent approximately 3% of our total proved reserves.

Javelina

We own interests in and operate 17 wells (17.0 net to us) in the Javelina field in Hidalgo County in South Texas. These wells produce primarily from the Vicksburg formation at a depth of approximately 10,900 to 12,500 feet. Proved reserves attributable to our interests in the Javelina field are 4.5 Bcfe, which represents approximately 1% of our total proved reserves.

Las Hermanitas

We own interests in and operate 11 natural gas wells (11.0 net to us) in the Las Hermanitas field, located in Duval County, Texas. These wells produce from the Wilcox formation at depths from approximately 11,400 to 11,800 feet. Our proved reserves of 3.2 Bcfe in this field represent approximately 1% of our total proved reserves.

Other Regions

Approximately 2%, or 9.6 Bcfe, of our proved reserves are in other regions, primarily in New Mexico and the Mid-Continent region. We also have a large acreage position in Mississippi and Louisiana in the emerging Tuscaloosa Marine shale play. We own interests in 332 producing wells (78.5 net to us) in 15 fields within these regions. Net daily production from our other regions during 2015 totaled 3 MMcf of natural gas and 199 barrels of oil or 5 MMcfe per day.

Major Property Acquisitions

As a result of our acquisitions of producing oil and gas properties, we have added 1.1 Tcfe of proved oil and natural gas reserves over the past 25 years. In recent years we have focused more on acreage acquisition and drilling for reserve growth and have not completed any significant acquisitions of producing properties.

Oil and Natural Gas Reserves

The following table sets forth our estimated proved oil and natural gas reserves as of December 31, 2015:

	Oil (MBbls)	Natural Gas (MMcf)	Total (MMcfe)
Proved Developed:			
Producing	9,171	250,638	305,666
Non-producing	58	60,492	60,839
Total Proved Developed	9,229	311,130	366,505
Proved Undeveloped	—	258,466	258,466
Total Proved	9,229	569,596	624,971

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The following table sets forth our year end reserves as of December 31 for each of the last three fiscal years:

	2013		2014		2015	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Developed	13,914	344,278	16,247	324,598	9,229	311,130
Proved Undeveloped	8,062	108,375	4,607	170,668	—	258,466
Total Proved Reserves	21,976	452,653	20,854	495,266	9,229	569,596

Proved reserves that are attributable to existing producing wells are primarily determined using decline curve analysis and rate transient analysis, which incorporates the principles of hydrocarbon flow. Proved reserves attributable to producing wells with limited production history and for undeveloped locations are estimated using performance from analogous wells in the surrounding area and geologic data to assess the reservoir continuity. Technologies relied on to establish reasonable certainty of economic producibility include, but are not limited to, electrical logs, radioactivity logs, core analyses, geologic maps and available production data, seismic data and well test data.

There are numerous uncertainties inherent in estimating quantities of proved oil and natural gas reserves. Oil and natural gas reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revision of such estimate. Accordingly, reserve estimates are often different from the quantities of oil and natural gas that are ultimately recovered.

The average prices that we realized from sales of oil and natural gas and lifting costs including severance and ad valorem taxes and transportation costs, for each of the last three fiscal years were as follows:

	Year Ended December 31,		
	2013	2014	2015
Oil Price - \$/Bbl	\$100.20	\$90.37	\$46.19
Natural Gas Price - \$/Mcf	\$3.38	\$4.16	\$2.30
Lifting costs - \$/Mcfe	\$1.22	\$1.48	\$1.35

Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent the average first of the month prices received at the point of sale for the last twelve months. These prices have been adjusted from posted prices for both location and quality differences. The oil and natural gas prices used for reserves estimation were as follows:

Year	Oil Price	Natural Gas Price
	(per Bbl)	(per Mcf)

2013	\$ 104.38	\$ 3.37
2014	\$ 92.55	\$ 3.96
2015	\$ 46.88	\$ 2.34

Reserves may be classified as proved undeveloped if there is a high degree of confidence that the quantities will be recovered, and they are scheduled to be drilled within five years of their initial inclusion as proved reserves, unless specific circumstances justify a longer time. In connection with estimating proved undeveloped reserves for our December 31, 2015 reserve report, reserves on undrilled acreage were limited to those that are reasonably certain of production when drilled where we can verify the continuity of the reservoir. At December 31, 2015, we also limited our estimates of proved undeveloped reserves to wells that we currently plan to drill and where we have adequate capital resources to enable us to drill them. Using empirical evidence, we utilize control points and sample sizes to show continuity in the reservoir. We reflect changes to undeveloped reserves that occur in the same field as revisions to the extent that proved undeveloped locations are revised due to changes in future development plans, including changes to proposed lateral lengths, development spacing and timing of development.

As of December 31, 2015, our proved undeveloped reserves were comprised of 258.5 Bcf of natural gas. All of our proved undeveloped reserves are associated with our Haynesville and Bossier shale properties where our drilling program in 2015 was focused. Our natural gas proved undeveloped reserves increased by 87.8 Bcf during 2015. This increase was primarily related to the reserve additions of 135.6 Bcf of natural gas related to our Haynesville and Bossier shale drilling program which were partially offset by undeveloped reserves converted to developed reserves of 55.1 Bcf. In 2015, we focused on drilling natural gas wells due to the weak oil prices. Seven of the Haynesville shale wells we drilled in 2015 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at December 31, 2015. Our oil proved undeveloped reserves decreased by 4.6 MMBbls during 2015. This decrease was primarily due to converting 0.1 MMBbls of our proved undeveloped oil reserves to developed in 2015, divestiture of 2.4 MMBbls and price related downward revisions of 2.1 MMBbls attributable to proved undrilled locations that are no longer economic to drill.

As of December 31, 2014, our proved undeveloped reserves included 4.6 MMBbls of oil and 170.7 Bcf of natural gas, for a total of 198.3 Bcfe of undeveloped reserves. All of our undeveloped oil reserves and 3 Bcf of natural gas of our proved undeveloped reserves were associated with our Eagle Ford shale properties in South and East Texas. The proved undeveloped reserves associated with our Haynesville and Bossier shale properties represented approximately 153 Bcf of our proved undeveloped natural gas reserves at December 31, 2014. The remaining proved undeveloped natural gas reserves are primarily associated with developing reserves in our Wilcox and Vicksburg reservoirs in South Texas. In 2014, we focused on drilling our oil properties. 51 of the Eagle Ford shale wells we drilled in 2014 resulted in conversions of proved undeveloped reserves to proved developed producing reserves at December 31, 2014. Our proved undeveloped oil reserves decreased by 3.5 MMBbls during 2014. This decrease was primarily due to converting 4.7 MMBbls of our proved undeveloped oil reserves to developed in 2014, new reserves additions of 2.6 MMBbls and price and other revisions which decreased our reserves by 1.4 MMBbls. Our proved undeveloped natural gas reserves increased by 62 Bcf at December 31, 2014 as compared with December 31, 2013. This increase was primarily related to proved undeveloped reserve additions of 76 Bcf of natural gas associated with our 2015 natural gas drilling program, which were partially offset by undeveloped reserves converted to developed reserves of 2 Bcf and price and other revisions which reduced our reserves by 12 Bcfe.

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The following table presents the changes in our estimated proved undeveloped oil and natural gas reserves for the years ended December 31, 2013, 2014 and 2015:

	Proved Undeveloped Reserves					
	2013		2014		2015	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Beginning Balance	10,510	75,019	8,062	108,375	4,607	170,668
Divestitures	—	—	—	—	(2,354)	(2,393)
Extension & Discoveries	583	36,578	2,640	76,009	—	135,574
Conversions from undeveloped to developed	(3,060)	(2,930)	(4,676)	(2,053)	(100)	(55,098)
Price, Performance and Other Revisions	29	(292)	(1,419)	(11,663)	(2,153)	9,715
Total Change	(2,448)	33,356	(3,455)	62,293	(4,607)	87,798
Ending Balance	8,062	108,375	4,607	170,668	—	258,466

The timing, by year, when our proved undeveloped reserve quantities are estimated to be converted to proved developed reserves is as follows:

Year ended December 31,	Proved Undeveloped Reserves					
	2013		2014		2015	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
2014	6,392	4,617	—	—	—	—
2015	1,328	369	375	43,659	—	—
2016	342	1,242	680	57,118	—	75,797
2017	—	56,129	1,475	25,924	—	92,912
2018	—	46,018	1,738	43,967	—	78,487
2019	—	—	339	—	—	11,270
2020	—	—	—	—	—	—
Total	8,062	108,375	4,607	170,668	—	258,466

The following table presents the timing of our estimated future development capital costs to be incurred for the years ended December 31, 2013, 2014 and 2015:

Year ended December 31,	Future Development Costs		
	Total Proved Undeveloped Reserves		
	2013	2014	2015
	(in millions)		
2014	\$ 265.2	\$ —	\$ —
2015	70.6	69.6	—
2016	24.1	108.8	76.9

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2017	98.1	113.5	96.5
2018	85.2	157.6	83.1
2019	—	13.5	13.5
2020	—	—	—
Total	\$ 543.2	\$ 463.0	\$ 270.0

The following table presents the changes in our estimated future development costs for the years ended December 31, 2014 and 2015:

	Haynesville/			
	Bossier	Eagle Ford	All Other	
	Shale	Shale	Properties	Total
	(in millions)			
Total as of December 31, 2013	\$ 152.1	\$ 357.6	\$ 33.5	\$543.2
Development Costs Incurred	—	(211.1)	—	(211.1)
Additions and Revisions	41.9	88.9	0.1	130.9
Total Changes	41.9	(122.2)	0.1	(80.2)
Total as of December 31, 2014	194.0	235.4	33.6	463.0
Development Costs Incurred	(73.0)	(11.7)	—	(84.7)
Divestitures	—	(111.9)	—	(111.9)
Additions and Revisions	149.0	(111.8)	(33.6)	3.6
Total Changes	76.0	(235.4)	(33.6)	(193.0)
Total as of December 31, 2015	\$270.0	\$ —	\$ —	\$270.0

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2015 of \$270.0 million decreased by \$193.0 million from our estimated future capital costs of \$463.0 million as of December 31, 2014. During 2015, we incurred approximately \$84.7 million to develop proved undeveloped reserves primarily in our Haynesville and Bossier shale properties. Our Haynesville and Bossier shale natural gas focused future capital expenditures increased by \$76.0 million, our Eagle Ford shale oil focused future capital expenditures decreased by \$235.4 million and our other properties future capital expenditures decreased by \$33.6 million.

Our estimated future capital costs to develop proved undeveloped reserves as of December 31, 2014 of \$463.0 million decreased by \$80.2 million from our estimated future capital costs of \$543.2 million as of December 31, 2013. We incurred approximately \$211.1 million during 2014 to develop proved undeveloped reserves, all of which was in our Eagle Ford shale properties. Our oil focused future capital expenditures decreased by \$122.2 million and our natural gas focused capital expenditures increased by \$41.9 million.

The estimates of our oil and natural gas reserves were determined by Lee Keeling and Associates, Inc. ("Lee Keeling"), an independent petroleum engineering firm. Lee Keeling has been providing consulting engineering and geological services for over fifty years. Lee Keeling's professional staff is comprised of qualified petroleum engineers who are experienced in all productive areas of the United States. The technical person responsible for review of our reserve estimates at Lee Keeling meets the requirements regarding qualifications, independence, objectivity and confidentiality set forth in the Standards Pertaining to Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers. Lee Keeling does not own any interests in our properties and is not employed on a contingent fee basis.

We have established, and maintain, internal controls designed to provide reasonable assurance that the estimates of proved reserves are computed and reported in accordance with rules and regulations promulgated by the SEC. These internal controls include documented process workflows, employing qualified professional engineering and geological personnel, and on-going education for personnel involved in our reserves estimation process. Our internal audit function routinely tests our processes and controls. Inputs to our reserves estimation process, which we provide to Lee Keeling for use in their reserves evaluation, are based upon our historical results for production history, oil and natural gas prices, lifting and development costs, ownership interests and other required data. Our Reservoir Engineering Department, comprised of qualified petroleum engineers and technical support staff, works with our

operating, accounting, land and marketing departments in order to accumulate the information required for the reserves estimation process. Our Vice President of Reservoir Engineering is the primary person in charge of overseeing our reserve estimates and our Reservoir Engineering Department. He has a B.S. Degree and a Masters Degree in Petroleum Engineering, is a Registered Professional Engineer and has over thirty-five years of experience in various technical roles within the oil and gas industry. During the reserves estimation process our petroleum engineers work with Lee Keeling to ensure that all data we provide is properly reflected in the final reserves estimates and they consult with Lee Keeling throughout the reserves estimation process on technical questions regarding the reserve estimates. We also regularly communicate with Lee Keeling throughout the year about our operations and the potential impact of operational changes and events on our reserve estimates.

We did not provide estimates of total proved oil and natural gas reserves during the years ended December 31, 2013, 2014 or 2015 to any federal authority or agency, other than the SEC.

Drilling Activity Summary

During the three-year period ended December 31, 2015, we drilled development and exploratory wells as set forth in the table below:

	2013		2014		2015	
	Gross	Net	Gross	Net	Gross	Net
Development:						
Oil	75	51.6	76	51.0	4	4.0
Gas	2	2.0	1	0.2	10	9.6
Dry	—	—	—	—	—	—
	77	53.6	77	51.2	14	13.6
Exploratory:						
Oil	—	—	3	2.8	1	—
Gas	—	—	—	—	—	—
Dry	—	—	1	1.0	—	—
	—	—	4	3.8	1	—
Total	77	53.6	81	55.0	15	13.6

In 2016 to the date of this report, we have not drilled any new wells and we have no wells currently in the process of being drilled.

Producing Well Summary

The following table sets forth the gross and net producing oil and natural gas wells in which we owned an interest at December 31, 2015:

	Oil		Natural Gas	
	Gross	Net	Gross	Net
Arkansas	—	—	15	8.0
Kansas	—	—	8	4.4

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Louisiana	17	5.2	438	252.7
Mississippi	2	1.0	—	—
New Mexico	1	—	92	14.2
Oklahoma	10	1.2	131	18.2
Texas	216	141.8	619	411.1
Wyoming	—	—	26	1.9
Total	246	149.2	1,329	710.5

We operate 952 of the 1,575 producing wells presented in the above table. As of December 31, 2015, we owned interests in 14 wells containing multiple completions, which means that a well is producing from more than one completed zone. Wells with more than one completion are reflected as one well in the table above.

Acreage

The following table summarizes our developed and undeveloped leasehold acreage at December 31, 2015, all of which is onshore in the continental United States. We have excluded acreage in which our interest is limited to a royalty or overriding royalty interest.

	Developed		Undeveloped	
	Gross	Net	Gross	Net
Arkansas	1,280	684	—	—
Kansas	6,400	4,064	—	—
Louisiana	91,825	58,897	61,215	55,705
Mississippi	2,016	1,944	38,060	33,493
New Mexico	10,240	1,896	—	—
Oklahoma	38,080	5,707	—	—
Texas	113,552	67,895	3,667	2,249
Wyoming	13,440	927	—	—
Total	276,833	142,014	102,942	91,447

Our undeveloped acreage expires as follows:

Expires in 2016	24	%
Expires in 2017	37	%
Expires in 2018	34	%
Thereafter	5	%
	100	%

Title to our oil and natural gas properties is subject to royalty, overriding royalty, carried and other similar interests and contractual arrangements customary in the oil and gas industry, liens incident to operating agreements and for current taxes not yet due and other minor encumbrances. All of our oil and natural gas properties are pledged as collateral under our bank credit facility. As is customary in the oil and gas industry, we are generally able to retain our ownership interest in undeveloped acreage by production of existing wells, by drilling activity which establishes commercial reserves sufficient to maintain the lease, by payment of delay rentals or by the exercise of contractual extension rights.

Markets and Customers

The market for our production of oil and natural gas depends on factors beyond our control, including the extent of domestic production and imports of oil and natural gas, the proximity and capacity of natural gas pipelines and other transportation facilities, demand for oil and natural gas, the marketing of competitive fuels and the effects of state and federal regulation. The oil and gas industry also competes with other industries in supplying the energy and fuel requirements of industrial, commercial and individual consumers.

Our oil production is currently sold under short-term contracts with a duration of six months or less. The contracts require the purchasers to purchase the amount of oil production that is available at prices tied to the spot oil markets. Our natural gas production is primarily sold under contracts with various terms and priced on first of the month index prices or on daily spot market prices. Approximately 50% of our 2015 natural gas sales were priced utilizing first of the month index prices and approximately 50% were priced utilizing daily spot prices. BP Energy Company and its subsidiaries and Shell Oil Company and its subsidiaries accounted for 52% and 25%, respectively, of our total 2015 sales. The loss of either of these customers would not have a material adverse effect on us as there is an available market for our crude oil and natural gas production from other purchasers.

We have entered into longer term marketing arrangements to ensure that we have adequate transportation to get our natural gas production in North Louisiana to the markets. As an alternative to constructing our own gathering and treating facilities, we have entered into a variety of gathering and treating agreements with midstream companies to transport our natural gas to the long-haul natural gas pipelines. We have entered into certain agreements with a major natural gas marketing company to provide us with firm transportation for 15,000 MMBtu per day for our North Louisiana natural gas production on the long-haul pipelines. These agreements expire from 2016 to 2019. To the extent we are not able to deliver the contracted natural gas volumes, we may be responsible for the transportation costs. Our production available to deliver under these agreements in North Louisiana is expected to exceed the firm transportation arrangements we have in place. In addition, the marketing company managing the firm transportation is required to use reasonable efforts to supplement our deliveries should we have a shortfall during the term of the agreements.

Competition

The oil and gas industry is highly competitive. Competitors include major oil companies, other independent energy companies and individual producers and operators, many of which have financial resources, personnel and facilities substantially greater than we do. We face intense competition for the acquisition of oil and natural gas properties and leases for oil and gas exploration.

Regulation

General. Various aspects of our oil and natural gas operations are subject to extensive and continually changing regulation, as legislation affecting the oil and natural gas industry is under constant review for amendment or expansion. Numerous departments and agencies, both federal and state, are authorized by statute to issue, and have issued, rules and regulations binding upon the oil and natural gas industry and its individual members. The Federal Energy Regulatory Commission, or "FERC", regulates the transportation and sale for resale of natural gas in interstate commerce pursuant to the Natural Gas Act of 1938, or "NGA", and the Natural Gas Policy Act of 1978, or "NGPA". In 1989, however, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all remaining price and nonprice controls affecting all "first sales" of natural gas, effective January 1, 1993, subject to the terms of any private contracts that may be in effect. While sales by producers of natural gas and all sales of crude oil, condensate and natural gas liquids can currently be made at uncontrolled market prices, in the future Congress could reenact price controls or enact other legislation with detrimental impact on many aspects of our business. Under the provisions of the Energy Policy Act of 2005 (the "2005 Act"), the NGA has been amended to prohibit any form of market manipulation with the purchase or sale of natural gas, and the FERC has issued new regulations that are intended to increase natural gas pricing transparency. The 2005 Act has also significantly increased the penalties for violations of the NGA. The FERC has issued Order No. 704 et al. which requires a market participant to make an annual filing if it has sales or purchases equal to or greater than 2.2 million MMBtu in the reporting year to facilitate price transparency.

Regulation and transportation of natural gas. Our sales of natural gas are affected by the availability, terms and cost of transportation. The price and terms for access to pipeline transportation are subject to extensive regulation. The FERC requires interstate pipelines to provide open-access transportation on a not unduly discriminatory basis for similarly situated shippers. The FERC frequently reviews and modifies its regulations regarding the transportation of natural gas, with the stated goal of fostering competition within the natural gas industry.

Intrastate natural gas transportation is subject to regulation by state regulatory agencies. The Texas Railroad Commission has been changing its regulations governing transportation and gathering services provided by intrastate pipelines and gatherers. While the changes by these state regulators affect us only indirectly, they are intended to further enhance competition in natural gas markets. We cannot predict what further action the FERC or state regulators will take on these matters; however, we do not believe that we will be affected differently in any material respect than other natural gas producers with which we compete by any action taken.

Additional proposals and proceedings that might affect the natural gas industry are pending before Congress, the FERC, state commissions and the courts. The natural gas industry historically has been very heavily regulated; therefore, there is no assurance that the less stringent regulatory approach pursued by the FERC, Congress and state regulatory authorities will continue.

Federal leases. Some of our operations are located on federal oil and natural gas leases that are administered by the Bureau of Land Management ("BLM") of the United States Department of the Interior. These leases are issued through competitive bidding and contain relatively standardized terms. These leases require compliance with detailed Department of Interior and BLM regulations and orders that are subject to interpretation and change. These leases are also subject to certain regulations and orders promulgated by the Department of Interior's Bureau of Ocean Energy Management, Regulation & Enforcement ("BOEMRE"), through its Minerals Revenue Management Program, which is responsible for the management of revenues from both onshore and offshore leases.

Oil and natural gas liquids transportation rates. Our sales of crude oil, condensate and natural gas liquids are not currently regulated and are made at market prices. In a number of instances, however, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to FERC jurisdiction under the Interstate Commerce Act. In other instances, the ability to transport and sell such products is dependent on pipelines whose rates, terms and conditions of service are subject to regulation by state regulatory bodies under state statutes. The price received from the sale of these products may be affected by the cost of transporting the products to market.

The FERC's regulation of pipelines that transport crude oil, condensate and natural gas liquids under the Interstate Commerce Act is generally more light-handed than the FERC's regulation of natural gas pipelines under the NGA. FERC-regulated pipelines that transport crude oil, condensate and natural gas liquids are subject to common carrier obligations that generally ensure non-discriminatory access. With respect to interstate pipeline transportation subject to regulation of the FERC under the Interstate Commerce Act, rates generally must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates are permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system (based on inflation) for transportation rates governed by the Interstate Commerce Act that allowed for an increase or decrease in the transportation rates. The FERC's regulations include a methodology for such pipelines to change their rates through the use of an index system that establishes ceiling levels for such rates. The mandatory five year review in 2005 revised the methodology for this index to be based on Producer Price Index for Finished Goods (PPI-FG) plus 1.3 percent for the period July 1, 2006 through June 30, 2011. The mandatory five year review in 2012 revised the methodology for this index to be based on PPI-FG plus 2.65 percent for the period July 1, 2011 through June 30, 2016. The regulations provide that each year the Commission will publish the oil pipeline index after the PPI-FG becomes available.

With respect to intrastate crude oil, condensate and natural gas liquids pipelines subject to the jurisdiction of state agencies, such state regulation is generally less rigorous than the regulation of interstate pipelines. State agencies have generally not investigated or challenged existing or proposed rates in the absence of shipper complaints or protests. Complaints or protests have been infrequent and are usually resolved informally.

We do not believe that the regulatory decisions or activities relating to interstate or intrastate crude oil, condensate or natural gas liquids pipelines will affect us in a way that materially differs from the way it affects other crude oil, condensate and natural gas liquids producers or marketers.

Environmental regulations. We are subject to stringent federal, state and local laws. These laws, among other things, govern the issuance of permits to conduct exploration, drilling and production operations, the amounts and types of materials that may be released into the environment, the discharge and disposition of waste materials, the remediation of contaminated sites and the reclamation and abandonment of wells, sites and facilities. Numerous governmental departments issue rules and regulations to implement and enforce such laws, which are often difficult and costly to comply with and which carry substantial civil and even criminal penalties for failure to comply. Some laws, rules and regulations relating to protection of the environment may, in certain circumstances, impose strict liability for environmental contamination, rendering a person liable for environmental damages and cleanup cost without regard to negligence or fault on the part of such person. Other laws, rules and regulations may restrict the rate of oil and natural gas production below the rate that would otherwise exist or even prohibit exploration and production activities in sensitive areas. In addition, state laws often require various forms of remedial action to prevent pollution, such as closure of inactive pits and plugging of abandoned wells. The regulatory burden on the oil and natural gas industry increases our cost of doing business and consequently affects our profitability. These costs are considered a normal, recurring cost of our on-going operations. Our domestic competitors are generally subject to the same laws and regulations.

We believe that we are in substantial compliance with current applicable environmental laws and regulations and that continued compliance with existing requirements will not have a material adverse impact on our operations. However, environmental laws and regulations have been subject to frequent changes over the years, and the imposition of more stringent requirements or new regulatory schemes such as carbon "cap and trade" programs could have a material adverse effect upon our capital expenditures, earnings or competitive position, including the suspension or cessation of operations in affected areas. As such, there can be no assurance that material cost and liabilities will not be incurred in the future.

The Comprehensive Environmental Response, Compensation and Liability Act, or "CERCLA", imposes liability, without regard to fault, on certain classes of persons that are considered to be responsible for the release of a "hazardous substance" into the environment. These persons include the current or former owner or operator of the disposal site or sites where the release occurred and companies that disposed or arranged for the disposal of hazardous substances. Under CERCLA, such persons may be subject to joint and several liability for the cost of investigating and cleaning up hazardous substances that have been released into the environment, for damages to natural resources and for the cost of certain health studies. In addition, companies that incur liability frequently also confront third party claims because it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by hazardous substances or other pollutants released into the environment from a polluted site.

The Federal Solid Waste Disposal Act, as amended by the Resource Conservation and Recovery Act of 1976, or "RCRA", regulates the generation, transportation, storage, treatment and disposal of hazardous wastes and can require cleanup of hazardous waste disposal sites. RCRA currently excludes drilling fluids, produced waters and other wastes associated with the exploration, development or

production of oil and natural gas from regulation as "hazardous waste". Disposal of such non-hazardous oil and natural gas exploration, development and production wastes usually are regulated by state law. Other wastes handled at exploration and production sites or used in the course of providing well services may not fall within this exclusion. Moreover, stricter standards for waste handling and disposal may be imposed on the oil and natural gas industry in the future. From time to time, legislation is proposed in Congress that would revoke or alter the current exclusion of exploration, development and production wastes from RCRA's definition of "hazardous wastes", thereby potentially subjecting such wastes to more stringent handling, disposal and cleanup requirements. If such legislation were enacted, it could have a significant impact on our operating costs, as well as the oil and natural gas industry in general. The impact of future revisions to environmental laws and regulations cannot be predicted.

Our operations are also subject to the Clean Air Act, or "CAA", and comparable state and local requirements. Amendments to the CAA were adopted in 1990 and contain provisions that may result in the gradual imposition of certain pollution control requirements with respect to air emissions from our operations. On April 17, 2012, the U. S. Environmental Protection Agency or "EPA" promulgated new emission standards for the oil and gas industry. These rules require a nearly 95 percent reduction in volatile organic compounds ("VOCs") emitted from hydraulically fractured gas wells by January 1, 2015. This significant reduction in emissions is to be accomplished primarily through the use of "green completions" (i.e., capturing natural gas that currently escapes to the air). These rules also have notification and reporting requirements. On September 23, 2014, EPA revised the emission requirements for storage tanks emitting certain levels of VOCs requiring a 95% reduction of VOC emissions by April 15, 2014 and April 15, 2015 (depending upon the date of construction of the storage tank). On December 19, 2014, EPA finalized updates and clarifications to these emission standards for the oil and gas industry. We believe our operations comply in all material respects with these emission limitations. Recently, EPA proposed new regulations on August 18, 2015 that would require further reductions in VOC and methane emissions. In addition to reducing emissions from hydraulically fractured wells, the proposed rules would require emission reductions further downstream, including equipment in the natural gas transmission segment of the industry. Should these latest proposed rules be adopted by EPA, we may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

The Federal Water Pollution Control Act of 1972, as amended, or the "Clean Water Act", imposes restrictions and controls on the discharge of produced waters and other wastes into navigable waters. Permits must be obtained to discharge pollutants into state and federal waters and to conduct construction activities in waters and wetlands. Certain state regulations and the general permits issued under the Federal National Pollutant Discharge Elimination System program prohibit the discharge of produced waters and sand, drilling fluids, drill cuttings and certain other substances related to the oil and natural gas industry into certain coastal and offshore waters, unless otherwise authorized. Further, the EPA has adopted regulations requiring certain oil and natural gas exploration and production facilities to obtain permits for storm water discharges. Costs may be associated with the treatment of wastewater or developing and implementing storm water pollution prevention plans. The Clean Water Act and comparable state statutes provide for civil, criminal and administrative penalties for unauthorized discharges for oil and other pollutants and impose liability on parties responsible for those discharges for the cost of cleaning up any environmental damage caused by the release and for natural resource damages resulting from the release. We believe that our operations comply in all material respects with the requirements of the Clean Water Act and state statutes enacted to control water pollution.

The Federal Safe Drinking Water Act of 1974, as amended, requires EPA to develop minimum federal requirements for Underground Injection Control ("UIC") programs and other safeguards to protect public health by preventing injection wells from contaminating underground sources of drinking water.

The UIC program does not regulate wells that are solely used for production. However, EPA has authority to regulate hydraulic fracturing when diesel fuels are used in fluids or propping agents. In February 2014, EPA issued new guidance on when UIC permitting requirements apply to fracking fluids containing diesel. We believe our operations will not be materially adversely affected by the new guidance, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

Federal regulators require certain owners or operators of facilities that store or otherwise handle oil to prepare and implement spill prevention, control, countermeasure and response plans relating to the possible discharge of oil into surface waters. The Oil Pollution Act of 1990 ("OPA") contains numerous requirements relating to the prevention and response to oil spills in the waters of the United States. The OPA subjects owners of facilities to strict joint and several liability for all containment and cleanup costs and certain other damages relating to a spill. Noncompliance with OPA may result in varying civil and criminal penalties and liabilities.

Executive Order 13158, issued on May 26, 2000, directs federal agencies to safeguard existing Marine Protected Areas, or "MPAs", in the United States and establish new MPAs. The order requires federal agencies to avoid harm to MPAs to the extent permitted by law and to the maximum extent practicable. It also directs the EPA to propose new regulations under the Clean Water Act to ensure appropriate levels of protection for the marine environment. This order has the potential to adversely affect our operations by restricting areas in which we may carry out future exploration and development projects and/or causing us to incur increased operating expenses.

Certain flora and fauna that have officially been classified as "threatened" or "endangered" are protected by the Endangered Species Act. This law prohibits any activities that could "take" a protected plant or animal or reduce or degrade its habitat area. If endangered species are located in an area we wish to develop, the work could be prohibited or delayed and/or expensive mitigation might be required.

Other statutes that provide protection to animal and plant species and which may apply to our operations include, but are not necessarily limited to, the Oil Pollution Act, the Emergency Planning and Community Right to Know Act, the Marine Mammal Protection Act, the Marine Protection, Research and Sanctuaries Act, the Fish and Wildlife Coordination Act, the Fishery Conservation and Management Act, the Migratory Bird Treaty Act and the National Historic Preservation Act. These laws and regulations may require the acquisition of a permit or other authorization before construction or drilling commences and may limit or prohibit construction, drilling and other activities on certain lands lying within wilderness or wetlands and other protected areas and impose substantial liabilities for pollution resulting from our operations. The permits required for our various operations are subject to revocation, modification and renewal by issuing authorities. In addition, laws such as the National Environmental Policy Act and the Coastal Zone Management Act may make the process of obtaining certain permits more difficult or time consuming, resulting in increased costs and potential delays that could affect the viability or profitability of certain activities.

Certain statutes such as the Emergency Planning and Community Right to Know Act require the reporting of hazardous chemicals manufactured, processed, or otherwise used, which may lead to heightened scrutiny of the company's operations by regulatory agencies or the public. In 2012, the EPA adopted a new reporting requirement, the Petroleum and Natural Gas Systems Greenhouse Gas Reporting Rule (40 C.F.R. Part 98, Subpart W), which requires certain onshore petroleum and natural gas facilities to begin collecting data on their emissions of greenhouse gases ("GHGs") in January 2012, with the first annual reports of those emissions due on September 28, 2012. GHGs include gases such as methane, a primary component of natural gas, and carbon dioxide, a byproduct of burning natural gas. Different GHGs have different global warming potentials with CO₂ having the lowest global warming potential, so

emissions of GHGs are typically expressed in terms of CO₂ equivalents, or CO₂e. The rule applies to facilities that emit 25,000 metric tons of CO₂e or more per year, and requires onshore petroleum and natural gas operators to group all equipment under common ownership or control within a single hydrocarbon basin together when determining if the threshold is met. These greenhouse gas reporting rules were amended on October 22, 2015 to expand the number of sources and operations that are subject to these rules. We have determined that these reporting requirements apply to us and we believe we have met all of the EPA required reporting deadlines and strive to ensure accurate and consistent emissions data reporting. Other EPA actions with respect to the reduction of greenhouse gases (such as EPA's Greenhouse Gas Endangerment Finding, and EPA's Prevention of Significant Deterioration and Title V Greenhouse Gas Tailoring Rule) and various state actions have or could impose mandatory reductions in greenhouse gas emissions. We are unable to predict at this time how much the cost of compliance with any legislation or regulation of greenhouse gas emissions will be in future periods.

Such changes in environmental laws and regulations which result in more stringent and costly reporting, or waste handling, storage, transportation, disposal or cleanup activities, could materially affect companies operating in the energy industry. Adoption of new regulations further regulating emissions from oil and gas production could adversely affect our business, financial position, results of operations and prospects, as could the adoption of new laws or regulations which levy taxes or other costs on greenhouse gas emissions from other industries, which could result in changes to the consumption and demand for natural gas. We may also be assessed administrative, civil and/or criminal penalties if we fail to comply with any such new laws and regulations applicable to oil and natural gas production.

In June 2009, the United States House of Representatives passed the American Clean Energy and Security Act of 2009. A similar bill, the Clean Energy Jobs and American Power Act, introduced in the Senate, did not pass. Both bills contained the basic feature of establishing a "cap and trade" system for restricting greenhouse gas emissions in the United States. Under such a system, certain sources of greenhouse gas emissions would be required to obtain greenhouse gas emission "allowances" corresponding to their annual emissions of greenhouse gases. The number of emission allowances issued each year would decline as necessary over time to meet overall emission reduction goals. As the number of greenhouse gas emission allowances declines each year, the cost or value of allowances is expected to escalate significantly. It appears that the prospects for a cap and trade system such as that proposed in these bills have dimmed significantly; however, the EPA has moved ahead with its efforts to regulate GHG emissions from certain sources by rule. The EPA issued Subpart W of the Final Mandatory Reporting of Greenhouse Gases Rule, which required petroleum and natural gas systems that emit 25,000 metric tons of CO₂e or more per year to begin collecting GHG emissions data under a new reporting system. We believe we have met all of the reporting requirements under these new regulations. Beyond measuring and reporting, the EPA issued an "Endangerment Finding" under section 202(a) of the Clean Air Act, concluding greenhouse gas pollution threatens the public health and welfare of current and future generations. The EPA has adopted regulations that would require permits for and reductions in greenhouse gas emissions for certain facilities. States in which we operate may also require permits and reductions in GHG emissions. Since all of our oil and natural gas production is in the United States, these laws or regulations that have been or may be adopted to restrict or reduce emissions of greenhouse gases could require us to incur substantial increased operating costs, and could have an adverse effect on demand for the oil and natural gas we produce. On January 14, 2015, the Obama Administration announced that, pursuant to the Administration's Climate Action Plan, the EPA will propose a rule to regulate methane and volatile organic compound emissions from new and modified oil and gas sources. The proposed rule was published in the Federal Register on August 18, 2015. A final rule is expected in 2016.

The Administration's announcement also stated that other federal agencies, including the Bureau of Land Management, will impose new or more stringent regulations on the oil and gas sector that will have the effect of further reducing methane emissions. In 2010 the Bureau of Land Management began implementation of a proposed oil and gas leasing reform. The leasing reform requires, among other things, a more detailed environmental review prior to leasing oil and natural gas resources on federal lands, increased public engagement in the development of Master Leasing Plans prior to leasing areas where intensive new oil and gas development is anticipated, and a comprehensive parcel review process with greater public involvement in the identification of key environmental resource values before a parcel is leased. New leases would incorporate adaptive management stipulations, requiring lessees to monitor and respond to observed environmental impacts, possibly through the implementation of expensive new control measures or curtailment of operations, potentially reducing profitability. The leasing reform policy could have the effect of reducing the amount of new federal lands made available for lease, increasing the competition for and cost of available parcels. On March 26, 2015, the Bureau of Land Management adopted a new rule concerning hydraulic fracturing on federal land. The new rule requires increased well integrity testing, increased requirements for the managing of fluids, and the disclosure of chemicals used in fracturing. This rule was challenged in federal district court in Wyoming and a preliminary injunction was issued on September 30, 2015 that stayed the effect of the new rule until the litigation was completed. Due to the ongoing litigation and the uncertainty on whether the courts will uphold the rule in whole or in part, we cannot at this time predict what effect the new rule will have on our operations.

On August 16, 2012, the EPA adopted final regulations under the Clean Air Act that, among other things, require additional emissions controls for natural gas and natural gas liquids production, including New Source Performance Standards to address emissions of sulfur dioxide and volatile organic compounds ("VOCs") and a separate set of emission standards to address hazardous air pollutants frequently associated with such production activities. The final regulations require the reduction of VOC emissions from natural gas wells through the use of reduced emission completions or "green completions" on all hydraulically fractured wells constructed or refractured after January 1, 2015. For well completion operations occurring at such well sites before January 1, 2015, the final regulations allow operators to capture and direct flowback emissions to completion combustion devices, such as flares, in lieu of performing green completions. These regulations also establish specific new requirements regarding emissions from dehydrators, storage tanks and other production equipment. On September 23, 2014, the EPA revised the emission requirements for storage tanks emitting certain levels of VOCs requiring a 95% reduction of VOC emissions by April 15, 2014 and April 15, 2015 (depending on the date of construction of the storage tank). On August 18, 2015, EPA proposed additional amendments to these rules that would require further reductions in VOC and methane emissions. In addition to reducing emissions from hydraulically fractured wells, the proposed rules would require emission reductions further downstream, including equipment in the natural gas transmission segment of the industry. Should these latest proposed rules be adopted by EPA, we may be required to incur certain capital expenditures in the future for air pollution control equipment in connection with obtaining and maintaining operating permits and approvals for air emissions. However, we believe our operations will not be materially adversely affected by any such requirements, and the requirements are not expected to be any more burdensome to us than to other similarly situated companies involved in oil and natural gas exploration and production activities.

Regulation of oil and natural gas exploration and production. Our exploration and production operations are subject to various types of regulation at the federal, state and local levels. Such regulations include requiring permits and drilling bonds for the drilling of wells, regulating the location of wells, the method of drilling and casing wells and the surface use and restoration of properties upon which wells are drilled. Many states also have statutes or regulations addressing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum rates of production from oil and natural gas wells and the regulation of spacing, plugging and abandonment of such wells. Some state statutes limit the rate at which oil and natural gas can be produced from our properties.

State regulation. Most states regulate the production and sale of oil and natural gas, including requirements for obtaining drilling permits, the method of developing new fields, the spacing and operation of wells and the prevention of waste of oil and gas resources. The rate of production may be regulated and the maximum daily production allowable from both oil and gas wells may be established on a market demand or conservation basis or both.

Office and Operations Facilities

Our executive offices are located at 5300 Town and Country Blvd., Suite 500 in Frisco, Texas 75034 and our telephone number is (972) 668-8800. We lease office space in Frisco, Texas covering 66,382 square feet at a monthly rate of \$124,466. This lease expires on December 31, 2021. We also own production offices and pipe yard facilities near Marshall, Pleasanton and Zapata, Texas and Logansport, Louisiana.

Employees

As of December 31, 2015, we had 125 employees and utilized contract employees for certain of our field operations. We consider our employee relations to be satisfactory.

Directors and Executive Officers

The following table sets forth certain information concerning our executive officers and directors.

Name	Position with Company	Age
M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors	60
Roland O. Burns	President, Chief Financial Officer, Secretary and Director	55
Mack D. Good	Chief Operating Officer	65
D. Dale Gillette	Vice President of Legal and General Counsel	70
Michael D. McBurney	Vice President of Marketing	60
Daniel K. Presley	Vice President of Accounting, Controller and Treasurer	55
Russell W. Romoser	Vice President of Reservoir Engineering	64
LaRae L. Sanders	Vice President of Land	53
Richard D. Singer	Vice President of Financial Reporting	61
Blaine M. Stribling	Vice President of Corporate Development	45
Elizabeth B. Davis	Director	53
David K. Lockett	Director	61
Cecil E. Martin	Director	74
Frederic D. Sewell	Director	81
David W. Sledge	Director	59
Jim L. Turner	Director	70

A brief biography of each person who serves as an executive officer or director follows below.

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Executive Officers

M. Jay Allison has been our Chief Executive Officer since 1988. Mr. Allison was elected Chairman of the Board in 1997 and has been a director since 1987. From 1988 to 2013, Mr. Allison served as our President. From 1981 to 1987, he was a practicing oil and gas attorney with the firm of Lynch, Chappell & Alsup in Midland, Texas. Mr. Allison was Chairman of the board of directors of Bois d'Arc Energy, Inc. from the time of its formation in 2004 until its merger with Stone Energy Corporation in 2008. He received B.B.A., M.S. and J.D. degrees from Baylor University in 1978, 1980 and 1981, respectively. Mr. Allison also currently serves as a Director of Tidewater, Inc. and is on the Board of Regents for Baylor University.

Roland O. Burns has been our President since 2013, Chief Financial Officer since 1990, Secretary since 1991 and a director since 1999. Mr. Burns served as our Senior Vice President from 1994 to 2013 and Treasurer from 1990 to 2013. From 1982 to 1990, Mr. Burns was employed by the public accounting firm, Arthur Andersen. During his tenure with Arthur Andersen, Mr. Burns worked primarily in the firm's oil and gas audit practice. Mr. Burns was a director, Senior Vice President and the Chief Financial Officer of Bois d'Arc Energy, Inc. from the time of its formation in 2004 until its merger with Stone Energy Corporation in 2008. Mr. Burns received B.A. and M.A. degrees from the University of Mississippi in 1982 and is a Certified Public Accountant. Mr. Burns also serves on the Board of Directors of the Cotton Bowl Athletic Association.

Mack D. Good returned as our Chief Operating Officer in March 2015. Mr. Good previously served as our Chief Operating Officer from 2004 until 2011, when he retired. From 1997 until 2004 he served in various other management and engineering positions with us. From 1983 until 1997 Mr. Good was with Enserch Exploration, Inc., serving in various engineering and operations management positions. Mr. Good received a B.S. of Biology/Chemistry from Oklahoma State University in 1975 and a B.S. degree of Petroleum Engineering from the University of Tulsa in 1983.

D. Dale Gillette became our General Counsel and Vice President of Legal in 2014. He has been our General Counsel since 2006. From 2006 until 2014, Mr. Gillette was also our Vice President of Land. Prior to joining us, Mr. Gillette practiced law extensively in the energy sector for 34 years, most recently as a partner with Gardere Wynne Sewell LLP, and before that with Locke Liddell & Sapp LLP (now known as Locke Lord LLP). During that time he represented independent exploration and production companies and large financial institutions in numerous oil and gas transactions. Mr. Gillette has also served as corporate counsel in the legal department of Mesa Petroleum Co. and in the legal department of Enserch Corp. Mr. Gillette holds B.A. and J.D. degrees from the University of Texas and is a member of the State Bar of Texas.

Michael D. McBurney has been our Vice President of Marketing since 2013. Mr. McBurney has over 33 years of energy industry experience within the oil, natural gas, LNG, and power segments. Prior to joining us, Mr. McBurney worked for EXCO Resources, Inc., an independent exploration and production company where he was responsible for natural gas and natural gas liquids marketing. From 2000 to 2006, Mr. McBurney was with FPL Energy of Florida, where he was responsible for Fuel and Transportation logistics for large scale power generation facilities located throughout the U.S. Mr. McBurney received a B.B.A. in Finance from the University of North Texas in 1978.

Daniel K. Presley was named our Treasurer in 2013. Mr. Presley, who has been with us since 1989, also continues to serve as our Vice President of Accounting and Controller, positions he has had held since 1997 and 1991, respectively. Prior to joining us, Mr. Presley had six years of experience with several independent oil and gas companies including AmBrit Energy, Inc. Prior thereto, Mr. Presley spent two and one-half years with B.D.O. Seidman, a public accounting firm. Mr. Presley received a B.B.A. degree from Texas A & M University in 1983.

Russell W. Romoser has been our Vice President of Reservoir Engineering since 2012. Mr. Romoser has over 39 years of experience as a reservoir engineer both with industry and with a petroleum engineering consulting firm. Prior to joining us, Mr. Romoser served eleven years as the Acquisitions Engineering Manager for EXCO Resources, Inc. Mr. Romoser received a B.S. Degree in Petroleum Engineering in 1975 and a Masters Degree in Petroleum Engineering in 1976 from the University of Texas and is a Registered Professional Engineer in Oklahoma and Texas.

LaRae L. Sanders was named our Vice President of Land in 2014. Ms. Sanders has been with us since 1995. She has served as Land Manager since 2007, and has been instrumental in all of our active development programs and major acquisitions. Prior to joining us, Ms. Sanders held positions with Bridge Oil Company and Kaiser-Francis Oil Company, as well as other independent exploration and production companies. Ms. Sanders is a Certified Professional Landman with 35 years of experience. She became the nation's first Certified Professional Lease and Title Analyst in 1990.

Richard D. Singer has been our Vice President of Financial Reporting since 2005. Mr. Singer has over 39 years of experience in financial accounting and reporting. Prior to joining us, Mr. Singer most recently served as an assistant controller for Holly Corporation from 2004 to 2005 and as assistant controller for Santa Fe International Corporation from 1988 to 2002. Mr. Singer received a B.S. degree from the Pennsylvania State University in 1976 and is a Certified Public Accountant.

Blaine M. Stribling has been our Vice President of Corporate Development since 2012. From 2007 to 2012, Mr. Stribling served as our Asset & Corporate Development Manager. Prior to joining us, Mr. Stribling managed a development project team at Encana Oil & Gas from 2005 to 2007. Prior to 2005 he worked in various petroleum engineering operations management positions of increasing responsibility for several independent oil and gas exploration and development companies. Mr. Stribling received a B.S. Degree in Petroleum Engineering from the Colorado School of Mines.

Outside Directors

Elizabeth B. Davis has served as a director since 2014. Dr. Davis is currently the President of Furman University. Dr. Davis was the Executive Vice President and Provost for Baylor University until July 2014, and served as Interim Provost from 2008 until 2010. Prior to her appointment as Provost, she was a professor of accounting in the Hankamer School of Business at Baylor University where she also served as associate dean for undergraduate programs and as acting chair for the Department of Accounting and Business Law. Prior to joining Baylor University, she worked for the public accounting firm Arthur Andersen from 1984 to 1987.

David K. Lockett has served as a director since 2001. Mr. Lockett was a Vice President with Dell Inc. and held executive management positions in several divisions within Dell from 1991 until his retirement from Dell in 2012. Since November 2014, Mr. Lockett has served as President of Austex Fence & Deck in Austin, Texas. Between 2012 and 2014, Mr. Lockett, who has over 35 years of experience in the technology industry, provided consulting services to small and mid-size companies. Mr. Lockett was a director of Bois d'Arc Energy, Inc. from May 2005 until its merger with Stone Energy Corporation in August 2008.

Cecil E. Martin has served as a director since 1989 and is currently the chairman of our audit committee and our Lead Director. Mr. Martin is an independent commercial real estate investor who has primarily been managing his personal real estate investments since 1991. From 1973 to 1991, he also served as chairman of a public accounting firm in Richmond, Virginia. Mr. Martin was a director and chairman of the Audit Committee of Bois d'Arc Energy, Inc. from May 2005 until its merger with Stone Energy Corporation in August 2008. Mr. Martin also served on the board of directors of Crosstex Energy, Inc. and Crosstex Energy, L.P. until their merger with EnLink Midstream and EnLink Midstream Partners LP, respectively, in March 2014. Mr. Martin currently serves on the board of directors of Garrison Capital, Inc. He served as chairman of the compensation committee at Crosstex Energy L.P. and currently serves as chairman of the audit committee at Garrison Capital, Inc. Mr. Martin is a Certified Public Accountant.

Frederic D. Sewell has served as a director since 2012. Mr. Sewell has extensive experience in the oil and gas industry, where he has had a distinguished career as an executive leader and a petroleum engineer. Mr. Sewell was the co-founder of Netherland, Sewell & Associates, Inc., a worldwide oil and gas consulting firm, where he served as the chairman and chief executive officer until his retirement in 2008. Mr. Sewell is presently the President and Chief Executive Officer of Sovereign Resources LLC, an exploration and production company that he founded.

David W. Sledge has served as a director since 1996. Mr. Sledge is the Chief Operating Officer of ProPetro Services, Inc. Mr. Sledge was President and Chief Operating Officer of Sledge Drilling Company until it was acquired by Basic Energy Services, Inc. in April 2007 and served as a Vice President of Basic Energy Services, Inc. from April 2007 to February 2009. He served as an area operations manager for Patterson-UTI Energy, Inc. from May 2004 until January 2006. From March 2009 through October 2011, and from October 1996 until May 2004, Mr. Sledge managed his personal investments in oil and gas exploration activities. Mr. Sledge was a director of Bois d'Arc Energy, Inc. from May 2005 until its merger with Stone Energy Corporation in August 2008. Mr. Sledge is a past director of the International Association of Drilling Contractors and is a past chairman of the Permian Basin chapter of this association.

Jim L. Turner has served as a director since 2014. Mr. Turner currently serves as principal of JLT Beverages, L.P., a position he has held since 1996. Mr. Turner was also recently named the Chief Executive Officer of JLT Automotive, Inc. which owns and operates an automobile dealership in Texas. Mr. Turner served as President and Chief Executive Officer of Dr. Pepper/Seven Up Bottling Group, Inc., from its formation in 1999 through 2005, when he sold his interest in that company. Prior to that, Mr. Turner served as Owner/Chairman of the Board and Chief Executive Officer of the Turner Beverage Group, the largest privately owned independent bottler in the United States. Mr. Turner currently serves as a director for Dean Foods Company and Crown Holdings, Inc. He also serves as Vice Chairman and Chair-elect of the board of directors of Baylor Scott & White Health.

Available Information

Our executive offices are located at 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034. Our telephone number is (972) 668-8800. We file annual, quarterly and current reports, proxy statements and other documents with the SEC under the Securities Exchange Act of 1934. The public may read and copy any materials that we file with the SEC at the SEC's Public Reference Room at 100 F Street N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. In addition, the SEC maintains a website that contains reports, proxy and information statements, and other information that is electronically filed with the SEC. The public can obtain any documents that we file with the SEC at www.sec.gov. We also make available free of charge on our website (www.comstockresources.com) our Annual Report on Form 10-K, quarterly reports on Form 10-Q, current reports on Form 8-K and, if applicable, amendments to those reports filed or furnished pursuant to Section 13(a) of the Exchange Act as soon as reasonably practicable after we file such material with, or furnish it to, the SEC.

ITEM 1A. Risk Factors

You should carefully consider the following risk factors as well as the other information contained or incorporated by reference in this report, as these important factors, among others, could cause our actual results to differ from our expected or historical results. It is not possible to predict or identify all such factors. Consequently, you should not consider any such list to be a complete statement of all of our potential risks or uncertainties.

An extended period of depressed oil and natural gas prices will adversely affect our business, financial condition, cash flow, liquidity, results of operations and our ability to meet our capital expenditure obligations and financial commitments.

Our business is heavily dependent upon the prices of, and demand for, oil and natural gas. Historically, the prices for oil and natural gas have been volatile and are likely to remain volatile in the future. Oil and natural gas prices have declined substantially since mid 2014 and have continued to decline into early 2016. For example, during the year ended December 31, 2015, commodity prices changed significantly, with the settlement price for West Texas Intermediate ("WTI") crude oil ranging from a high of approximately \$61.43 per barrel to a low of approximately \$34.73 per barrel and settlement prices for Henry Hub natural gas ranging from a high of approximately \$3.23 per Mcf to a low of approximately \$1.76 per Mcf. Oil and natural gas price weakness has continued into 2016 and, through February 24, 2016, the WTI settlement price of crude oil had a low of approximately \$26.21 per barrel, and the Henry Hub settlement price of natural gas had a low of approximately \$1.78 per Mcf.

The prices we receive for our oil and natural gas production are subject to wide fluctuations and depend on numerous factors beyond our control, including the following:

- the domestic and foreign supply of oil and natural gas;
- weather conditions;
- the price and quantity of imports of oil and natural gas;
- political conditions and events in other oil-producing and natural gas-producing countries, including embargoes, hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the actions of the Organization of Petroleum Exporting Countries, or OPEC;
- domestic government regulation, legislation and policies;
- the level of global oil and natural gas inventories;
- technological advances affecting energy consumption;
- the price and availability of alternative fuels; and
- overall economic conditions.

Lower oil and natural gas prices will adversely affect:

- our revenues, profitability and cash flow from operations;
- the value of our proved oil and natural gas reserves;
- the economic viability of certain of our drilling prospects;
- our borrowing capacity; and
- our ability to obtain additional capital.

Our debt service requirements could adversely affect our operations and limit our growth.

We had \$1.3 billion principal amount of debt as of December 31, 2015.

Our outstanding debt has important consequences, including, without limitation:

- a portion of our cash flow from operations is required to make debt service payments;
- our ability to borrow additional amounts for capital expenditures (including acquisitions) or other purposes is limited; and
- our debt limits our ability to capitalize on significant business opportunities, our flexibility in planning for or reacting to changes in market conditions and our ability to withstand competitive pressures and economic downturns.

In addition, future acquisition or development activities may require us to alter our capitalization significantly. These changes in capitalization may significantly increase our debt. Moreover, our ability to meet our debt service obligations and to reduce our total debt will be dependent upon our future performance, which will be subject to general economic conditions and financial, business and other factors affecting our operations, many of which are beyond our control. If we are unable to generate sufficient cash flow from operations in the future to service our indebtedness and to meet other commitments, we will be required to adopt one or more alternatives, such as refinancing or restructuring our indebtedness, selling material assets or seeking to raise additional debt or equity capital. We cannot assure you that any of these actions could be effected on a timely basis or on satisfactory terms or that these actions would enable us to continue to satisfy our capital requirements.

Our debt agreements contain a number of significant covenants. These covenants limit our ability to, among other things:

- borrow additional money;
- merge, consolidate or dispose of assets;
- make certain types of investments;
- enter into transactions with our affiliates; and
- pay dividends.

Our failure to comply with any of these covenants could cause a default under our bank credit facility and the respective indentures governing our senior notes. A default, if not waived, could result in acceleration of our indebtedness, in which case the debt would become immediately due and payable. If this occurs, we may not be able to repay our debt or borrow sufficient funds to refinance it given the current status of the credit markets. Even if new financing is available, it may not be on terms that are acceptable to us. Complying with these covenants may cause us to take actions that we otherwise would not take or not take actions that we otherwise would take.

Our access to capital markets may be limited in the future.

Adverse changes in the financial and credit markets could negatively impact our ability to grow production and reserves and meet our future obligations. In addition, the continuation of the current low oil and natural gas price environment, or further declines of oil and natural gas prices, will affect our ability to obtain financing for acquisitions and drilling activities and could result in a reduction in drilling activity which results in the loss of acreage through lease expirations, both of which could negatively affect our ability to replace reserves.

Our future production and revenues depend on our ability to replace our reserves.

Our future production and revenues depend upon our ability to find, develop or acquire additional oil and natural gas reserves that are economically recoverable. Our proved reserves will generally decline as reserves are depleted, except to the extent that we conduct successful exploration or development activities or acquire properties containing proved reserves, or both. To increase reserves and production, we must continue our acquisition and drilling activities. We cannot assure you that we will have adequate capital resources to conduct acquisition and drilling activities or that our acquisition and drilling activities will result in significant additional reserves or that we will have continuing success drilling productive wells at low finding and development costs. Furthermore, while our revenues may increase if prevailing oil and natural gas prices increase significantly, our finding costs for additional reserves could also increase.

Prospects that we decide to drill may not yield oil or natural gas in commercially viable quantities or quantities sufficient to meet our targeted rate of return.

A prospect is a property in which we own an interest or have operating rights and that has what our geoscientists believe, based on available seismic and geological information, to be an indication of potential oil or natural gas. Our prospects are in various stages of evaluation, ranging from a prospect that is ready to be drilled to a prospect that will require substantial additional evaluation and interpretation. There is no way to predict in advance of drilling and testing whether any particular prospect will yield oil or natural gas in sufficient quantities to recover drilling or completion costs or to be economically viable. The use of seismic data and other technologies and the study of producing fields in the same area will not enable us to know conclusively prior to drilling whether oil or natural gas will be present or, if present, whether oil or natural gas will be present in commercial quantities. The analysis that we perform using data from other wells, more fully explored prospects and/or producing fields may not be useful in predicting the characteristics and potential reserves associated with our drilling prospects. If we drill additional unsuccessful wells, our drilling success rate may decline and we may not achieve our targeted rate of return.

Our business involves many uncertainties and operating risks that can prevent us from realizing profits and can cause substantial losses.

Our success depends on the success of our exploration and development activities. Exploration activities involve numerous risks, including the risk that no commercially productive natural gas or oil reserves will be discovered. In addition, these activities may be unsuccessful for many reasons, including weather, cost overruns, equipment shortages and mechanical difficulties. Moreover, the successful drilling of a natural gas or oil well does not ensure we will realize a profit on our investment. A variety of factors, both geological and market-related, can cause a well to become uneconomical or only marginally economical. In addition to their costs, unsuccessful wells can hurt our efforts to replace production and reserves.

Our business involves a variety of operating risks, including:

- unusual or unexpected geological formations;
- fires;
- explosions;
- blow-outs and surface cratering;
- uncontrollable flows of natural gas, oil and formation water;
- natural disasters, such as hurricanes, tropical storms and other adverse weather conditions;
- pipe, cement, or pipeline failures;

- casing collapses;
- mechanical difficulties, such as lost or stuck oil field drilling and service tools;
- abnormally pressured formations; and
- environmental hazards, such as natural gas leaks, oil spills, pipeline ruptures and discharges of toxic gases.

If we experience any of these problems, well bores, gathering systems and processing facilities could be affected, which could adversely affect our ability to conduct operations.

We could also incur substantial losses as a result of:

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

We maintain insurance against "sudden and accidental" occurrences, which may cover some, but not all, of the risks described above. Most significantly, the insurance we maintain will not cover the risks described above which occur over a sustained period of time. Further, there can be no assurance that such insurance will continue to be available to cover all such cost or that such insurance will be available at a cost that would justify its purchase. The occurrence of a significant event not fully insured or indemnified against could have a material adverse effect on our financial condition and results of operations.

We operate in a highly competitive industry, and our failure to remain competitive with our competitors, many of which have greater resources than we do, could adversely affect our results of operations.

The oil and natural gas industry is highly competitive in the search for and development and acquisition of reserves. Our competitors often include companies that have greater financial and personnel resources than we do. These resources could allow those competitors to price their products and services more aggressively than we can, which could hurt our profitability. Moreover, 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 close transactions in a highly competitive environment.

If oil and natural gas prices decline further or remain low for an extended period of time, we may be required to further write-down the carrying values and/or the estimates of total reserves of our oil and natural gas properties, which would constitute a non-cash charge to earnings and adversely affect our results of operations.

Accounting rules applicable to us require that we review periodically the carrying value of our oil and natural gas properties for possible impairment. Based on specific market factors and circumstances at the time of prospective impairment reviews and the continuing evaluation of development plans, production data, economics and other factors, we may be required to write down the carrying value of our oil and natural gas properties. A write-down constitutes a non-cash charge to earnings. During 2015, we recognized impairments of \$801.3 million which reduced the carrying value of our oil and natural gas properties. We may incur additional non-cash charges in the future, which could have a material adverse effect on our results of operations in the period taken. We may also reduce our estimates of the reserves that may be economically recovered, which could have the effect of reducing the total value of our reserves.

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

Reserve engineering is a subjective process of estimating the recovery from underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, the quantities of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas prices may all differ materially from those assumed in these estimates. The information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves is only estimated and should not be construed as the current market value of the oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our borrowing ability, our future prospects and the value of our common stock.

As of December 31, 2015, 41% of our total proved reserves were undeveloped and 10% were developed non-producing. These reserves may not ultimately be developed or produced. Furthermore, not all of our undeveloped or developed non-producing reserves may be ultimately produced at the time periods we have planned, at the costs we have budgeted, or at all. As a result, we may not find commercially viable quantities of oil and natural gas, which in turn may result in a material adverse effect on our results of operations.

Some of our undeveloped leasehold acreage is subject to leases that will expire unless production is established on units containing the acreage.

Leases on oil and gas properties normally have a term of three to five years and will expire unless, prior to expiration of the lease term, production in paying quantities is established. If the leases expire and we are unable to renew them, we will lose the right to develop the related properties. Our drilling plans for these areas are subject to change based upon various factors, including drilling results, commodity prices, the availability and cost of capital, drilling and production costs, availability of drilling services and equipment, gathering system and pipeline transportation constraints and regulatory approvals.

We pursue acquisitions as part of our growth strategy and there are risks in connection with acquisitions.

Our growth has been attributable in part to acquisitions of producing properties and companies. More recently we have been focused on acquiring acreage for our drilling program. We expect to continue to evaluate and, where appropriate, pursue acquisition opportunities on terms we consider favorable. However, we cannot assure you that suitable acquisition candidates will be identified in the future, or that we will be able to finance such acquisitions on favorable terms. In addition, we compete against other companies for acquisitions, and we cannot assure you that we will successfully acquire any material property interests. Further, we cannot assure you that future acquisitions by us will be integrated successfully into our operations or will increase our profits.

The successful acquisition of producing properties requires an assessment of numerous factors beyond our control, including, without limitation:

- recoverable reserves;
- exploration potential;
- future oil and natural gas prices;
- operating costs; and
- potential environmental and other liabilities.

In connection with such an assessment, we perform a review of the subject properties that we believe to be generally consistent with industry practices. The resulting assessments are inexact and their accuracy uncertain, and such a review may not reveal all existing or potential problems, nor will it necessarily permit us to become sufficiently familiar with the properties to fully assess their merits and deficiencies. Inspections may not always be performed on every well, and structural and environmental problems are not necessarily observable even when an inspection is made.

Additionally, significant acquisitions can change the nature of our operations and business depending upon the character of the acquired properties, which may be substantially different in operating and geologic characteristics or geographic location than our existing properties. While our current operations are focused in Texas, Louisiana and Mississippi, we may pursue acquisitions or properties located in other geographic areas.

If we are unsuccessful at marketing our oil and natural gas at commercially acceptable prices, our profitability will decline.

Our ability to market oil and natural gas at commercially acceptable prices depends on, among other factors, the following:

- the availability and capacity of gathering systems and pipelines;
- federal and state regulation of production and transportation;
- changes in supply and demand; and
- general economic conditions.

Our inability to respond appropriately to changes in these factors could negatively affect our profitability.

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

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

We are subject to extensive governmental laws and regulations that may adversely affect the cost, manner or feasibility of doing business.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, and operating safety. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may harm our business, results of operations and financial condition. We may be required to make large and unanticipated capital expenditures to comply with governmental laws and regulations, such as:

- lease permit restrictions;
- drilling bonds and other financial responsibility requirements, such as plug and abandonment bonds;
- spacing of wells;
- unitization and pooling of properties;
- safety precautions;
- regulatory requirements; and
- taxation.

Under these laws and regulations, we could be liable for:

- personal injuries;
- property and natural resource damages;
- well reclamation costs; and
- governmental sanctions, such as fines and penalties.

Our operations could be significantly delayed or curtailed and our cost of operations could significantly increase as a result of regulatory requirements or restrictions. We are unable to predict the ultimate cost of compliance with these requirements or their effect on our operations.

Our operations are substantially dependent on the availability of water. Restrictions on our ability to obtain water may have an adverse effect on our financial condition, results of operations and cash flows.

Water is an essential component of both the drilling and hydraulic fracturing processes. Historically, we have been able to purchase water from various sources for use in our operations. In recent years South Texas has experienced the lowest inflows of water in recent history. As a result of this severe drought, some local water districts may begin restricting the use of water subject to their jurisdiction for drilling and hydraulic fracturing in order to protect the local water supply. If we are unable to obtain water to use in our operations from local sources, we may be unable to economically produce oil and natural gas, which could have an adverse effect on our financial condition, results of operations and cash flows.

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

Our oil and natural gas operations are subject to stringent federal, state and local laws and regulations relating to the release or disposal of materials into the environment and otherwise relating to environmental protection. These laws and regulations:

- require the acquisition of one or more permits before drilling commences;
- impose limitations on where drilling can occur and/or requires mitigation before authorizing drilling in certain locations;
- restrict the types, quantities and concentration of substances that can be released into the environment in connection with drilling and production activities;
- require reporting of significant releases, and annual reporting of the nature and quantity of emissions, discharges and other releases into the environment;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and
- impose substantial liabilities for pollution resulting from our operations.

Failure to comply with these laws and regulations may result in:

- the assessment of administrative, civil and criminal penalties;
- the incurrence of investigatory and/or remedial obligations; and
- the imposition of injunctive relief.

Changes in environmental laws and regulations occur frequently, and any changes that result in more stringent or costly restrictions on emissions, and/or waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to reach and maintain compliance and may otherwise have a material adverse effect on our industry in general and on our own results of operations, competitive position or financial condition. Under these environmental laws and regulations, we could be held strictly liable for the removal or remediation of previously released materials or property contamination regardless of whether we were responsible for the release or contamination or if our operations met previous standards in the industry at the time they were performed. Future environmental laws and regulations, including proposed legislation regulating climate change, may negatively impact our industry. The costs of compliance with these requirements may have an adverse impact on our financial condition, results of operations and cash flows.

Our hedging transactions could result in financial losses or could reduce our income. To the extent we have hedged a significant portion of our expected production and actual production is lower than we expected or the costs of goods and services increase, our profitability would be adversely affected.

To achieve more predictable cash flows and to reduce our exposure to adverse fluctuations in the prices of oil and gas, we have entered into and may in the future enter into hedging transactions for certain of our expected oil and natural gas production. These transactions could result in both realized and unrealized hedging losses.

The extent of our commodity price exposure is related largely to the effectiveness and scope of our derivative activities. For example, the derivative instruments we utilize are primarily based on NYMEX futures prices, which may differ significantly from the actual crude oil and gas prices we realize in our operations. Furthermore, we have adopted a policy that requires, and our revolving credit facility also requires, that we enter into derivative transactions related to only a portion of our expected production volumes and, as a result, we will continue to have direct commodity price exposure on the portion of our production volumes not covered by these derivative financial instruments.

Our actual future production may be significantly higher or lower than we estimate at the time we enter into derivative transactions. If our actual future production is higher than we estimated, we will have greater commodity price exposure than we intended. If our actual future production is lower than the nominal amount that is subject to our derivative financial instruments, we might be forced to satisfy all or a portion of our derivative transactions without the benefit of the cash flow from our sale or purchase of the underlying physical commodity, resulting in a substantial diminution in our profitability and liquidity. As a result of these factors, our derivative activities may not be as effective as we intend in reducing the volatility of our cash flows, and in certain circumstances may actually increase the volatility of our cash flows.

In addition, our hedging transactions are subject to the following risks:

- we may be limited in receiving the full benefit of increases in oil and gas prices as a result of these transactions;
- a counterparty may not perform its obligation under the applicable derivative financial instrument or may seek bankruptcy protection;
- there may be a change in the expected differential between the underlying commodity price in the derivative instrument and the actual price received; and
- the steps we take to monitor our derivative financial instruments may not detect and prevent violations of our risk management policies and procedures, particularly if deception or other intentional misconduct is involved.

The enactment of derivatives legislation and regulation could have an adverse effect on our ability to use derivative instruments to reduce the effect of commodity price, interest rate and other risks associated with our business.

In 2010, new comprehensive financial reform legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act ("Dodd-Frank"), was enacted that established federal oversight regulation of over-the-counter derivatives market and entities, such as us, that participate in that market. Dodd-Frank requires the Commodities Futures Trading Commission, or CFTC, the SEC and other regulators to promulgate rules and regulations implementing the new legislation. The final rules adopted under Dodd-Frank identify the types of products and the classes of market participants subject to regulation and will require us in connection with certain derivatives activities to comply with clearing and trade-execution requirements (or take steps to qualify for an exemption from such requirements). While

most of the regulations have been finalized, it is not possible at this time to predict with certainty the full effects of Dodd-Frank and CFTC rules on us or the timing of such effects. We believe that Dodd-Frank and associated regulations could significantly increase the cost of derivative contracts from additional recordkeeping and reporting requirements and through requirements to post collateral which could adversely affect our available liquidity. If we reduce our use of derivatives as a result of Dodd-Frank and associated 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. These consequences could have a material adverse effect on our consolidated financial position, results of operations and cash flows.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays as well as restrict our access to our oil and gas reserves.

Hydraulic fracturing is an essential and common practice that is used to stimulate production of oil and natural gas from dense subsurface rock formations such as shale and tight sands. We routinely apply hydraulic fracturing techniques in completing our wells. The process involves the injection of water, sand and additives under pressure into a targeted subsurface formation. The water and pressure create fractures in the rock formations, which are held open by the grains of sand, enabling the oil or natural gas to flow to the wellbore. The use of hydraulic fracturing is necessary to produce commercial quantities of oil and natural gas from many reservoirs including the Haynesville shale, Bossier shale, Eagle Ford shale, Tuscaloosa Marine shale, Cotton Valley and other tight natural gas and oil reservoirs. Substantially all of our proved oil and gas reserves that are currently not producing and our undeveloped acreage require hydraulic fracturing to be productive. All of the wells currently being drilled by us utilize hydraulic fracturing in their completion. We estimate we will incur approximately \$28.0 million for hydraulic fracturing services in connection with our 2016 drilling and completion program.

The use of hydraulic fracturing in our well completion activities could expose us to liability for negative environmental effects that might occur. Although we have not had any incidents related to hydraulic fracturing operations that we believe have caused any negative environmental effects, we have established operating procedures to respond and report any unexpected fluid discharge which might occur during our operations, including plans to remediate any spills that might occur. In the event that we were to suffer a loss related to hydraulic fracturing operations, our insurance coverage will be net of a deductible per occurrence and our ability to recover costs will be limited to a total aggregate policy limit of \$26.0 million, which may or may not be sufficient to pay the full amount of our losses incurred.

Drilling and completion activities are typically regulated by state oil and natural gas commissions. Our drilling and completion activities are conducted primarily in Louisiana and Texas. Texas adopted a law in June 2012 requiring disclosure to the Railroad Commission of Texas and the public of certain information regarding the components used in the hydraulic-fracturing process. Several proposals are before the United States Congress that, if implemented, would subject the process of hydraulic fracturing to regulation under the Safe Drinking Water Act. At the direction of Congress, the EPA is currently conducting an extensive, multi-year study into the potential effects of hydraulic fracturing on underground sources of drinking water, and the results of that study have the potential to impact the likelihood or scope of future legislation or regulation.

Potential changes to US federal tax regulations, if passed, could have an adverse effect on us.

The United States Congress continues to consider imposing new taxes and repealing many tax incentives and deductions that are currently used by independent oil and gas producers. Such changes include, but are not limited to:

- the elimination of current deductions for intangible drilling and development costs;
- the repeal of the percentage depletion allowance for oil and gas properties;
- an elimination of the deduction for U.S. oil and gas production activities;
- an extension of the amortization period for certain geological and geophysical expenditures; and
- implementation of a fee on non-producing leases located on federal lands.

It is unclear, however, whether any such changes will be enacted or how soon such changes could be effective. The passage of any legislation containing these or similar changes in U.S. federal income tax law could eliminate or defer certain tax deductions that are currently available with respect to oil and gas exploration and development, and any such changes could negatively affect our financial condition and results of operations. A reduction in operating cash flow could require us to reduce our drilling activities. Since none of these proposals have yet been included in new legislation, we do not know the ultimate impact they may have on our business.

Loss of our information and computer systems could adversely affect our business.

We are heavily dependent on our information systems and computer-based programs, including our well operations information, seismic data, electronic data processing and accounting data. If any of such programs or systems were to fail or create erroneous information in our hardware or software network infrastructure or we were subject to cyberspace breaches or attacks, possible consequences include our loss of communication links, inability to find, produce, process and sell oil and natural gas and inability to automatically process commercial transactions or engage in similar automated or computerized business activities. Any such consequence could have a material effect on our business.

Our business could be negatively impacted by security threats, including cyber-security threats and other disruptions.

As an oil and natural gas producer, we face various security threats, including cyber-security threats to gain unauthorized access to sensitive information or to render data or systems unusable, threats to the safety of our employees, threats to the security of our facilities and infrastructure or third party facilities and infrastructure, such as processing plants and pipelines, and threats from terrorist acts. Cyber-security attacks in particular are evolving and include, but are not limited to, malicious software, attempts to gain unauthorized access to data, and other electronic security breaches that could lead to disruptions in critical systems, unauthorized release of confidential or otherwise protected information and corruption of data. Although we utilize various procedures and controls to monitor and protect against these threats and to mitigate our exposure to such threats, there can be no assurance that these procedures and controls will be sufficient in preventing security threats from materializing. If any of these events were to materialize, they could lead to losses of sensitive information, critical infrastructure, personnel or capabilities, essential to our operations and could have a material adverse effect on our reputation, financial position, results of operations, or cash flows.

We are exposed to the credit risk of our customers and counterparties, and our credit risk management may not be adequate to protect against such risk.

We are subject to the risk of loss resulting from nonpayment and/or nonperformance by our customers and counterparties in the ordinary course of our business. Our credit procedures and policies may not be adequate to fully eliminate customer and counterparty credit risk particularly in light of the sustained declines in oil and natural gas prices since mid 2014. We cannot predict to what extent our business would be impacted by deteriorating conditions in the economy, including declines in our customers' and counterparties' creditworthiness. If we fail to adequately assess the creditworthiness of existing or future customers and counterparties, unanticipated deterioration in their creditworthiness and any resulting increase in nonpayment and/or nonperformance by them could cause us to write-down or write-off doubtful accounts. Such write-downs or write-offs could negatively affect our operating results in the periods in which they occur and, if significant, could have a material adverse effect on our business, results of operations, cash flows and financial condition.

Substantial exploration and development activities could require significant outside capital, which could dilute the value of our common shares and restrict our activities. Also, we may not be able to obtain needed capital or financing on satisfactory terms, which could lead to a limitation of our future business opportunities and a decline in our oil and natural gas reserves.

We expect to expend substantial capital in the acquisition of, exploration for and development of oil and natural gas reserves. In order to finance these activities, we may need to alter or increase our capitalization substantially through the issuance of debt or equity securities, the sale of non-strategic assets or other means. The issuance of additional equity securities could have a dilutive effect on the value of our common shares, and may not be possible on terms acceptable to us given the current volatility in the financial markets. The issuance of additional debt would require that a portion of our cash flow from operations be used for the payment of interest on our debt, thereby reducing our ability to use our cash flow to fund working capital, capital expenditures, acquisitions, dividends and general corporate requirements, which could place us at a competitive disadvantage relative to other competitors. Additionally, if our revenues decrease as a result of lower oil or natural gas prices, operating difficulties or declines in reserves, our ability to obtain the capital necessary to undertake or complete future exploration and development programs and to pursue other opportunities may be limited, which could result in a curtailment of our operations relating to exploration and development of our prospects, which in turn could result in a decline in our oil and natural gas reserves.

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

Our industry has experienced a shortage of drilling rigs, equipment, supplies and qualified personnel in prior years as the result of higher demand for these services. Shortages of drilling rigs, equipment or supplies or qualified personnel in the areas in which we operate could delay or restrict our exploration and development operations, which in turn could adversely affect our financial condition and results of operations because of our concentration in those areas.

We depend on our key personnel and the loss of any of these individuals could have a material adverse effect on our operations.

We believe that the success of our business strategy and our ability to operate profitably depend on the continued employment of M. Jay Allison, our Chief Executive Officer, and Roland O. Burns, our President and Chief Financial Officer, and a limited number of other senior management personnel. Loss of the services of Mr. Allison, Mr. Burns or any of those other individuals could have a material adverse effect on our operations.

Our insurance coverage may not be sufficient or may not be available to cover some liabilities or losses that we may incur.

If we suffer a significant accident or other loss, our insurance coverage will be net of our deductibles and may not be sufficient to pay the full current market value or current replacement value of our lost investment, which could result in a material adverse impact on our operations and financial condition. Our insurance does not protect us against all operational risks. We do not carry business interruption insurance. For some risks, we may not obtain insurance if we believe the cost of available insurance is excessive relative to the risks presented. Because third party drilling contractors are used to drill our wells, we may not realize the full benefit of workers' compensation laws in dealing with their employees. In addition, some risks, including pollution and environmental risks, generally are not fully insurable.

Provisions of our articles of incorporation, bylaws, Nevada law and our rights plan will make it more difficult to effect a change in control of us, which could adversely affect the price of our common stock.

Nevada corporate law and our articles of incorporation and bylaws contain provisions that could delay, defer or prevent a change in control of us. These provisions include:

- allowing for authorized but unissued shares of common and preferred stock;
- a classified board of directors;
- requiring special stockholder meetings to be called only by our chairman of the board, our chief executive officer, a majority of the board or the holders of at least 10% of our outstanding stock entitled to vote at a special meeting;
- requiring removal of directors by a supermajority stockholder vote;
- prohibiting cumulative voting in the election of directors; and
- Nevada control share laws that may limit voting rights in shares representing a controlling interest in us.

These provisions could make an acquisition of us by means of a tender offer or proxy contest or removal of our incumbent directors more difficult. As a result, these provisions could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

We adopted a rights plan in October 2015 to preserve our accumulated net operating losses. While this rights plan is intended to preserve our tax net operating losses, it effectively deters current and potential future purchases of our common stock above 4.9% of the total outstanding shares. This rights plan could make it more difficult for a third party to acquire us, even if doing so would benefit our stockholders, which may limit the price that investors are willing to pay in the future for shares of our common stock.

ITEM 1B. UNRESOLVED STAFF COMMENTS

None.

ITEM 3. LEGAL PROCEEDINGS

We are not a party to any legal proceedings which management believes will have a material adverse effect on our consolidated results of operations or financial condition.

ITEM 4. MINE SAFETY DISCLOSURES

Not applicable.

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PART II

ITEM 5. MARKET FOR REGISTRANT'S COMMON EQUITY, RELATED STOCKHOLDER MATTERS AND ISSUER PURCHASES OF EQUITY SECURITIES

Our common stock is listed for trading on the New York Stock Exchange under the symbol "CRK". The following table sets forth, on a per share basis for the periods indicated, the high and low sales prices by calendar quarter for the periods indicated as reported by the New York Stock Exchange.

	High	Low
2014 –First Quarter	\$23.15	\$16.22
Second Quarter	\$29.15	\$22.42
Third Quarter	\$29.49	\$18.30
Fourth Quarter	\$18.80	\$5.01
2015 –First Quarter	\$7.22	\$3.23
Second Quarter	\$5.44	\$3.29
Third Quarter	\$4.07	\$0.99
Fourth Quarter	\$3.38	\$1.60

As of February 26, 2016, we had 53,178,316 shares of common stock outstanding, which were held by 196 holders of record and approximately 15,000 beneficial owners who maintain their shares in "street name" accounts.

We paid a quarterly cash dividend on our common stock in 2014, resulting in total dividends paid of \$23.8 million. On February 13, 2015, we announced that the dividend was being suspended until oil and natural gas prices improve. Any future determination as to the payment of dividends will depend upon the results of our operations, capital requirements, our financial condition and such other factors as our board of directors may deem relevant.

Stockholder Return Performance

A peer group of companies is used by our compensation committee to benchmark our executives' compensation and to determine total stockholder return performance for purposes of vesting of performance share units granted to executives under our 2009 Long-term Incentive Plan. For 2015, the compensation committee utilized a peer group, which consisted of Approach Resources, Inc., Bill Barrett Corporation, Carrizo Oil & Gas Inc., Cimarex Energy Co., Laredo Petroleum Holdings Inc., Oasis Petroleum Inc., PDC Energy Inc., SM Energy, Inc., Stone Energy Corporation, Swift Energy Co., and Ultra Petroleum Corp.

The following graph compares the yearly percentage change in the cumulative total stockholder return on our common stock during the five years ended December 31, 2015 with the cumulative return on the New York Stock Exchange Index and the cumulative return for our peer group. The graph assumes that \$100.00 was invested on the last trading day of 2010, and that dividends, if any, were reinvested.

COMPARISON OF 5 YEAR CUMULATIVE TOTAL RETURN⁽¹⁾⁽²⁾

Among Comstock Resources, the NYSE Composite Index, and Our Peer Group

(1) \$100 invested on December 31, 2010 in stock or index, including reinvestment of dividends, fiscal year ending December 31.

(2) The data contained in the above graph is deemed to be furnished and not filed pursuant to Section 18 of the Securities Exchange Act of 1934, as amended, or otherwise subject to the liabilities of that section.

	As of December 31,					
Total Return Analysis	2010	2011	2012	2013	2014	2015
Comstock Resources	\$100.00	\$62.30	\$61.56	\$76.23	\$29.33	\$8.05
NYSE Composite	\$100.00	\$96.16	\$111.53	\$140.85	\$150.35	\$144.21
Peer Group	\$100.00	\$82.59	\$65.44	\$100.02	\$62.82	\$42.43

ITEM 6. SELECTED FINANCIAL DATA

The historical financial data presented in the table below as of and for each of the years in the five-year period ended December 31, 2015 are derived from our consolidated financial statements. The financial results are not necessarily indicative of our future operations or future financial results. The data presented below should be read in conjunction with our consolidated financial statements and the notes thereto and "Management's Discussion and Analysis of Financial Condition and Results of Operations".

Statement of Operations Data:

	Year Ended December 31,				
	2011	2012	2013	2014	2015
	(In thousands, except per share data)				
Revenues:					
Natural gas sales	\$354,123	\$203,651	\$188,453	\$165,461	\$109,753
Oil sales	80,244	181,163	231,837	389,770	142,669
Total oil and gas sales	434,367	384,814	420,290	555,231	252,422
Gain on sales of oil and gas properties	—	24,271	—	—	—
Total revenues	434,367	409,085	420,290	555,231	252,422
Operating expenses:					
Production taxes	3,670	11,727	14,524	23,797	10,286
Gathering and transportation	28,491	26,265	17,245	12,897	14,298
Lease operating ⁽¹⁾	46,552	51,248	52,844	60,283	64,502
Exploration	10,148	61,449	33,423	19,403	70,694
Depreciation, depletion and amortization	290,776	343,858	337,134	378,275	321,323
General and administrative, net	35,172	33,798	34,767	32,379	23,541
Impairment of oil and gas properties	60,817	25,368	652	60,268	801,347
Loss on sales of oil and gas properties	57	—	2,033	—	112,085
Total operating expenses	475,683	553,713	492,622	587,302	1,418,076
Operating loss	(41,316)	(144,628)	(72,332)	(32,071)	(1,165,654)
Other income (expenses):					
Gain on sale of marketable securities	35,118	26,621	7,877	—	—
Gain (loss) from derivative financial instruments	—	21,256	(8,388)	8,175	2,676
Net gain (loss) on extinguishment of debt	(1,096)	—	(17,854)	—	78,741
Other income	790	944	1,059	727	1,275
Interest expense	(41,592)	(57,906)	(73,242)	(58,631)	(118,592)
Total other income (expenses)	(6,780)	(9,085)	(90,548)	(49,729)	(35,900)

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Loss from continuing operations before income taxes	(48,096)	(153,713)	(162,880)	(81,800)	(1,201,554)
Benefit from income taxes	14,624	50,634	56,157	24,689	154,445
Loss from continuing operations	(33,472)	(103,079)	(106,723)	(57,111)	(1,047,109)
Income from discontinued operations, net of income taxes	—	3,019	147,752	—	—
Net income (loss)	\$(33,472)	\$(100,060)	\$41,029	\$(57,111)	\$(1,047,109)
Basic and diluted net income (loss) per share:					
Loss from continuing operations	\$(0.73)	\$(2.22)	\$(2.22)	\$(1.24)	\$(22.71)
Income from discontinued operations	—	0.06	3.07	—	—
Net Income (loss)	\$(0.73)	\$(2.16)	\$0.85	\$(1.24)	\$(22.71)
Dividends per common share	\$—	\$—	\$0.375	\$0.500	\$—
Basic and diluted weighted average shares outstanding	45,997	46,422	46,553	46,547	46,113

(1) Includes ad valorem taxes.

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Balance Sheet Data:

	As of December 31,				
	2011	2012	2013	2014	2015
	(In thousands)				
Cash and cash equivalents	\$8,460	\$4,471	\$2,967	\$2,071	\$134,006
Property and equipment, net	2,155,568	1,958,687	2,066,735	2,198,169	1,038,420
Total assets ⁽¹⁾	2,632,009	2,554,930	2,130,112	2,264,546	1,195,850
Total debt ⁽¹⁾	1,186,319	1,309,416	789,414	1,060,654	1,249,330
Stockholders' equity (deficit)	1,037,625	933,534	952,005	870,272	(171,258)

(1) Restated to reclassify debt issuance costs from total assets to total debt in the amount of \$10,589, \$14,967, \$9,286 and \$9,791 as of December 31, 2011, 2012, 2013, and 2014, respectively.

Cash Flow Data:

	Year Ended December 31,				
	2011	2012	2013	2014	2015
	(In thousands)				
Cash flows provided by operating activities from continuing operations	\$275,433	\$219,721	\$268,994	\$400,984	\$30,086
Cash flows used for investing activities from continuing operations	(597,809)	(205,393)	(408,678)	(634,787)	(161,725)
Cash flows provided by (used for) financing activities from continuing operations	673,381	117,502	(576,140)	232,907	263,574
Cash flows provided by (used for) operating activities of discontinued operations	—	42,508	(7,715)	—	—
Cash flows provided by (used for) investing activities of discontinued operations	(344,277)	(178,327)	722,035	—	—

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

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

Overview

We are an independent energy company engaged in the acquisition, exploration, development and production of oil and natural gas in the United States. We own interests in 1,575 producing oil and natural gas wells (859.7 net to us) and we operate 952 of these wells. In managing our business, we are concerned primarily with maximizing return on our stockholders' equity. To accomplish this goal, we focus on profitably increasing our oil and natural gas reserves and production.

In 2011, we acquired an undeveloped acreage position and some producing oil wells in Gaines and Reeves Counties in West Texas. We operated these properties, which we designated as our West Texas region, through May 2013 when we sold all of these properties for total proceeds of \$823.1 million. Accordingly, we are presenting our West Texas operations as discontinued operations in our financial statements for all periods presented. Unless indicated otherwise, the amounts in the accompanying tables and discussion relate to our continuing operations.

Our growth is driven primarily by acquisition, development and exploration activities. In 2015 our growth in natural gas production and proved reserves was primarily driven by our successful drilling activities. Under our current drilling budget, we plan to spend approximately \$98.0 million in 2016 for development and exploration activities, which will primarily be focused on natural gas projects. We are currently planning to drill nine horizontal natural gas wells (7.5 net to us) in 2016, targeting the Haynesville/Bossier shales. The actual number of wells that we drill will depend on oil and natural gas prices.

We use the successful efforts method of accounting, which allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration activities. Accordingly, our exploration costs consist of costs we incur to acquire and reprocess 3-D seismic data, impairments of our unevaluated leasehold where we were not successful in discovering reserves and the costs of unsuccessful exploratory wells that we drill.

We generally sell our oil and natural gas at current market prices at the point our wells connect to third party purchaser pipelines or terminals. We have entered into certain transportation and treating agreements with midstream and pipeline companies to transport a substantial portion of our natural gas production in North Louisiana to long-haul gas pipelines. We market our products several different ways depending upon a number of factors, including the availability of purchasers for the product, the availability and cost of pipelines near our wells, market prices, pipeline constraints and operational flexibility. Accordingly, our revenues are heavily dependent upon the prices of, and demand for, oil and natural gas. Oil and natural gas prices have historically been volatile and are likely to remain volatile in the future. Oil and natural gas prices have declined substantially since June 2014 and have continued to decline into early 2016.

Our operating costs are generally comprised of several components, including costs of field personnel, insurance, repair and maintenance costs, production supplies, fuel used in operations, transportation costs, workover expenses and state production and ad valorem taxes.

Like all oil and natural gas exploration and production companies, we face the constant challenge of replacing our reserves. Although in the past we have offset the effect of declining production rates from existing properties through successful acquisition and drilling efforts, there can be no assurance that we will be able to continue to offset production declines or maintain production at current rates through future acquisitions or drilling activity. Our future growth will depend on our ability to continue to add new reserves in excess of production.

Our operations and facilities are subject to extensive federal, state and local laws and regulations relating to the exploration for, and the development, production and transportation of, oil and natural gas, and operating safety. Future laws or regulations, any adverse changes in the interpretation of existing laws and regulations or our failure to comply with existing legal requirements may have an adverse effect on our business, results of operations and financial condition. Applicable environmental regulations require us to remove our equipment after production has ceased, to plug and abandon our wells and to remediate any environmental damage our operations may have caused. The present value of the estimated future costs to plug and abandon our oil and gas wells and to dismantle and remove our production facilities is included in our reserve for future abandonment costs, which was \$20.1 million as of December 31, 2015.

Prices for crude oil and natural gas have been highly volatile, and we are currently experiencing a period of extraordinarily low prices primarily due to an oversupply of crude oil and natural gas. As prices remain low, we will continue to experience low revenues and cash flows. We expect our oil production to decline in the future until we resume drilling on these properties. We expect our natural gas production to decline in the future to the extent that we do not offset this decline from production from the new wells we plan to drill in 2016 and future periods. Depending upon future prices and our production volumes,

our cash flows from our operating activities may not be sufficient to fund our capital expenditures, and we will need to either curtail drilling activity or we may seek additional borrowings which would increase our interest expense in 2016 and in future periods.

We recognized significant impairments of our proved oil and gas properties in 2015. We may need to recognize further impairments if oil and natural gas prices remain low, and as a result, the expected future cash flows from these properties becomes insufficient to recover their carrying value. Specifically, as part of the impairment review performed at December 31, 2015, we observed that a decline in excess of 30% for our future cash flow estimates for our Eagleville field in South Texas could result in an additional impairment being recorded in an amount that could be at least \$130.0 million. In addition, we may recognize additional impairments of our unevaluated oil and gas properties should we determine that we no longer intend to retain these properties for future oil and natural gas development.

Results of Operations

Year Ended December 31, 2015 Compared to Year Ended December 31, 2014

Our operating data for 2014 and 2015 is summarized below:

	Year Ended December 31,	
	2014	2015
Oil and Gas Sales (in thousands):		
Natural gas sales	\$165,461	\$109,753
Oil sales	389,770	142,669
Total oil and gas sales	\$555,231	\$252,422
Net Production Data:		
Natural gas (MMcf)	39,768	47,646
Oil (MBbls)	4,313	3,089
Natural gas equivalent (MMcfe)	65,645	66,207
Average Sales Price:		
Natural gas (\$/Mcf)	\$4.16	\$2.30
Oil (\$/Bbl)	\$90.37	\$46.19
Average equivalent price (\$/Mcfe)	\$8.46	\$3.81
Expenses (\$ per Mcfe):		
Production taxes	\$0.36	\$0.16
Gathering and transportation	\$0.20	\$0.22
Lease operating ⁽¹⁾	\$0.92	\$0.97
Depreciation, depletion and amortization ⁽²⁾	\$5.74	\$4.84

(1) Includes ad valorem taxes.

(2) Represents depreciation, depletion and amortization of oil and gas properties only.

Oil and gas sales. Our oil and gas sales decreased \$302.8 million (55%) in 2015 to \$252.4 million from \$555.2 million in 2014. Oil sales decreased by \$247.1 million (63%) from 2014 while our natural gas sales decreased by \$55.7 million (34%) from 2014. The decrease in oil sales was attributable to the 28% decline in oil production and a 49% decrease in our realized oil price in 2015. Our natural gas production increased by 20% from 2014 while our realized natural gas price decreased by 45%. Our drilling activity in the Haynesville and Bossier shale fields in East Texas and North Louisiana generated the natural gas production growth.

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Production taxes. Production taxes decreased \$13.5 million or 57% to \$10.3 million in 2015 from \$23.8 million in 2014. The decrease in 2015 is due to the 63% decline in our oil sales during the year. Much of our natural gas sales in 2014 and 2015 qualified for temporary exemption from state production taxes.

Gathering and transportation. Gathering and transportation costs in 2015 increased \$1.4 million (11%) to \$14.3 million as compared to \$12.9 million in 2014 due to the 20% increase in natural gas we produced during 2015. Gathering and transportation per Mcf produced improved from 2014 as the additional volumes produced in the Haynesville shale properties allowed us to lower our unit transportation costs.

Lease operating expenses. Our lease operating expenses, including ad valorem taxes, of \$64.5 million in 2015 were \$4.2 million or 7% higher than our operating expenses of \$60.3 million in 2014. Our lease operating expense per Mcfe produced rose by 6% to \$0.97 per Mcfe in 2015 as compared to \$0.92 per Mcfe in 2014. The increase in operating costs mainly reflects the higher lifting costs associated with our oil wells including additional costs incurred related to adding artificial lift to many of our producing oil wells.

Exploration expense. We incurred \$70.7 million in exploration expense in 2015 as compared to \$19.4 million in 2014. Exploration expense in 2015 consisted of \$69.0 million in impairments of unevaluated leasehold costs and \$1.7 million in rig termination fees. Our 2014 exploration cost consisted of \$11.8 million in dry hole costs, \$6.7 million in rig termination fees, \$0.5 million of impairments of unevaluated leasehold costs and \$0.4 million for the acquisition of seismic data.

Depreciation, depletion and amortization expense ("DD&A"). DD&A of \$321.3 million decreased by \$57.0 million (15%) from DD&A of \$378.3 million in 2014. Our DD&A rate per Mcfe produced averaged \$4.84 in 2015 as compared to \$5.74 for 2014. The decrease in DD&A expense and the DD&A rate primarily resulted from higher production from our lower cost natural gas properties.

General and administrative expenses. General and administrative expense of \$23.5 million for 2015 was 27% lower than general and administrative expense of \$32.4 million for 2014 primarily due to lower employee compensation in 2015 including stock based compensation which decreased to \$8.1 million in 2015 as compared to \$10.7 million in 2014.

Impairment of oil and gas properties. We assess the need for impairment of the capitalized costs for our oil and gas properties on a property basis. During 2015, with the substantial decline in management's estimates of future oil and natural gas prices, we recognized an impairment charge of \$801.3 million on our oil and gas properties. During 2014 we recognized an impairment charge of \$60.3 million.

Derivative financial instruments. We utilized oil and natural gas price swaps to manage our exposure to commodity prices and protect returns on investment from our drilling activities. We had gains of \$2.7 million and \$8.2 million on derivative financial instruments in 2015 and 2014, respectively. Our total net cash received from derivative financial instruments was \$1.2 million and \$9.1 million in 2015 and 2014, respectively.

The following tables present our oil and natural gas prices before and after the effect of cash settlements of our derivative financial instruments:

Average Realized Natural Gas Price:	2014	2015
Natural gas, per Mcf	\$4.16	\$2.30
Cash settlements on derivative financial instruments, per Mcf	—	0.03
Price per Mcf, including cash settlements on derivative financial instruments	\$4.16	\$2.33

Average Realized Oil Price:	2014	2015
Oil, per barrel	\$90.37	\$46.19
Cash settlements on derivative financial instruments, per barrel	2.13	—
Price per barrel, including cash settlements on derivative financial instruments	\$92.50	\$46.19

Interest expense. Interest expense increased \$60.0 million (102%) to \$118.6 million in 2015 from interest expense of \$58.6 million in 2014. The increase was primarily related to the refinancing of our bank credit facility with 10% secured senior notes in March 2015 and a reduction in the interest we capitalized in 2015. We issued \$700.0 million of senior secured notes in March 2015. We capitalized interest of \$0.9 million and \$10.2 million in 2015 and 2014, respectively.

Income taxes. The benefit from income taxes from continuing operations increased in 2015 to \$154.4 million from \$24.7 million in 2014 due to the higher net loss in 2015. Our effective tax rate of 12.9% in 2015 differed from the federal income tax rate of 35% primarily due to a valuation allowance on deferred tax assets of \$279.4 million.

Net loss. We reported a loss of \$1.0 billion or \$22.71 per share for 2015 as compared to a loss of \$57.1 million or \$1.24 per share for 2014. The loss in 2015 was primarily due to the oil and gas property impairment charges recognized, the loss on sale of oil and gas properties, lower oil and natural gas prices, higher exploration costs and higher interest expense. The net loss in 2014 was primarily due to impairments of proved and unproved properties, and other exploration costs.

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

Our operating data for 2013 and 2014 is summarized below:

	Year Ended December 31,	
	2013	2014
Oil and Gas Sales (in thousands):		
Natural gas sales	\$188,453	\$165,461
Oil sales	231,837	389,770
Total oil and gas sales	\$420,290	\$555,231
Net Production Data:		
Natural gas (MMcf)	55,694	39,768
Oil (MBbls)	2,314	4,313
Natural gas equivalent (MMcfe)	69,577	65,645
Average Sales Price:		
Natural gas (\$/Mcf)	\$3.38	\$4.16
Oil (\$/Bbl)	\$100.20	\$90.37
Average equivalent price (\$/Mcf)	\$6.04	\$8.46
Expenses (\$ per Mcfe):		
Production taxes	\$0.21	\$0.36
Gathering and transportation	\$0.25	\$0.20
Lease operating ⁽¹⁾	\$0.76	\$0.92
Depreciation, depletion and amortization ⁽²⁾	\$4.83	\$5.74

(1) Includes ad valorem taxes.

(2) Represents depreciation, depletion and amortization of oil and gas properties only.

Oil and gas sales. Our oil and gas sales increased \$134.9 million (32%) in 2014 to \$555.2 million from \$420.3 million in 2013. Oil sales in 2014 increased by \$157.9 million (68%) from 2013 while our natural gas sales decreased by \$23.0 million (12%) from 2013. The increase in oil sales was attributable to the 86% growth in oil production offset by a 10% decrease in our realized oil prices in 2014. Our drilling activity in the Eagleville and Giddings fields in South Texas principally generated the growth in the oil production. With limited drilling in our natural gas properties in 2014, our natural gas production fell by 29% from 2013 while our realized natural gas prices increased by 23%.

Production taxes. Production taxes increased \$9.3 million or 64% to \$23.8 million in 2014 from \$14.5 million in 2013. The increase in 2014 was due to the 68% growth in our oil sales during the year. Much of our natural gas sales in 2013 and 2014 qualified for a temporary exemption from state production taxes.

Gathering and transportation. Gathering and transportation costs in 2014 decreased \$4.3 million (25%) to \$12.9 million as compared to \$17.2 million in 2013 due to the lower natural gas volumes that we produced in North Louisiana in 2014.

Lease operating expenses. Our lease operating expenses, including ad valorem taxes, of \$60.3 million in 2014 were \$7.5 million or 14% higher than our operating expenses of \$52.8 million in 2013. Our lease operating expense per Mcfe produced increased by 21% to \$0.92 per Mcfe in 2014 as compared to \$0.76 per Mcfe in 2013. The increase in operating costs mainly reflects our growing oil production. Our oil wells are typically more costly to operate on a per Mcfe basis than our natural gas wells. The increase in our per unit costs is also partially attributable to the lower production on a Mcfe basis. Oil production comprised 39% of our total production in 2014 as compared to 20% in 2013.

Exploration expense. We incurred \$19.4 million in exploration expense in 2014 as compared to \$33.4 million in 2013. Exploration expense in 2014 consisted of \$11.8 million in dry hole costs, \$6.7 million in rig termination fees, \$0.5 million of impairments of unevaluated leasehold costs and \$0.4 million for the acquisition of seismic data. Our 2013 exploration cost consisted of \$33.0 million of impairments of unevaluated leasehold costs and \$0.4 million for the acquisition of seismic data.

Depreciation, depletion and amortization expense. DD&A of \$378.3 million increased by \$41.2 million (12%) from DD&A of \$337.1 million in 2013. Our DD&A rate per Mcfe produced averaged \$5.74 in 2014 as compared to \$4.83 for 2013. The increase in DD&A primarily resulted from the increased development costs per Mcfe associated with the oil wells drilled in 2014 and 2013.

General and administrative expenses. General and administrative expense of \$32.4 million for 2014 was 7% lower than general and administrative expense of \$34.8 million for 2013. The decrease is primarily related to stock-based compensation which decreased by \$2.1 million to \$10.7 million in 2014 as compared to \$12.8 million in 2013.

Impairment of oil and gas properties. We recorded impairments to our oil and gas properties of \$60.3 million and \$0.7 million in 2014 and 2013, respectively. These impairments relate to older, conventional oil and gas properties with declining production and limited potential for future investments.

Derivative financial instruments. We utilized oil price swaps to manage our exposure to oil prices and protect returns on investment from our drilling activities in 2013 and 2014. We had a gain of \$8.2 million and a loss of \$8.4 million on derivative financial instruments in 2014 and 2013, respectively. Our total net cash received from derivative financial instruments was \$9.1 million in 2014 and \$2.3 million in 2013.

The following table presents our crude oil equivalent prices before and after the effect of cash settlements of our derivative financial instruments:

Average Realized Oil Price:	2013	2014
Oil, per barrel	\$100.20	\$90.37
Cash settlements on derivative financial instruments, per barrel	0.99	2.13
Price per barrel, including cash settlements on derivative financial instruments	\$101.19	\$92.50

Interest expense. Interest expense decreased \$14.6 million (20%) to \$58.6 million in 2014 from interest expense of \$73.2 million in 2013. The decrease was primarily related to lower interest expense due to the retirement in September 2013 of our 8 % senior notes due in 2017. We capitalized interest of \$10.2 million and \$4.7 million in 2014 and 2013, respectively, which reduced interest expense. We had interest expense allocated to discontinued operations of \$8.4 million in 2013 of which \$2.0 million was capitalized. Average borrowings under our bank credit facility increased to \$319.2 million in 2014 as compared to \$201.5 million for 2013 and the average interest rate on the outstanding borrowings under our bank credit facility of 2.0% in 2014 was lower than the interest rate of 2.6% in 2013. Interest expense related to our outstanding senior notes decreased by 21% due to the retirement of our 8 % senior notes offset partially by the issuance an additional \$100.0 million of our 7¾% senior notes in 2014.

Income taxes. The benefit from income taxes from continuing operations decreased in 2014 to \$24.7 million from \$56.2 million in 2013 due to the lower net loss from continuing operations in 2014. Our effective tax rate of 30.2% in 2014 differed from the federal income tax rate of 35% primarily due to the effect of nondeductible compensation, state income taxes and an increase in the valuation allowance for state income tax net operating loss carry forwards.

Net loss. We reported a net loss from continuing operations of \$57.1 million or \$1.24 per share for 2014 as compared to a loss of \$106.7 million or \$2.22 per share for 2013. The net loss in 2014 was primarily due to impairments of proved and unproved properties and other exploration costs. The loss in 2013 was due to impairments of proved and unproved properties and a loss on early extinguishment of debt.

Net income from discontinued operations for 2013 of \$147.8 million, or \$3.07 per share, included a gain on the sale of our West Texas oil and gas properties of \$230.0 million (\$148.6 million after income taxes). Excluding the gain, the net loss from discontinued operations for the year ended December 31, 2013 was \$0.8 million.

Liquidity and Capital Resources

Funding for our activities has historically been provided by our operating cash flow, debt or equity financings and asset dispositions. For 2015, our primary source of funds was operating cash flow, borrowings and net proceeds from asset sales. Cash provided by operating activities in 2015 of \$30.1 million decreased \$370.9 million from \$401.0 million in 2014. Cash flow was lower than 2014 due to decreased revenues related to the decreased oil production and lower oil and gas prices along with higher interest expense from our senior notes issued in 2015. Our other primary source of funds in 2015 included net proceeds from our 10% senior secured notes offering of \$683.8 million, \$40.0 million of net borrowings under our bank credit facility and net proceeds from asset sales of \$102.5 million.

In 2014, our primary source of funds was operating cash flow and borrowings. Cash provided by operating activities from continuing operations in 2014 of \$401.0 million increased \$132.0 million (49%) from \$269.0 million in 2013 primarily due to the higher revenues related to increased oil production and higher natural gas prices in 2014. Our other primary source of funds during 2014 included \$103.3 million of proceeds from an additional issuance of our 7¾% senior notes and \$165.0 million of borrowings under our bank credit facility.

Our primary need for capital, in addition to funding our ongoing operations, relates to the acquisition, development and exploration of our oil and gas properties and servicing and retirement of our debt. In 2015, our capital expenditures of \$243.2 million represented a decrease of \$345.4 million as compared to 2014 capital expenditures of \$588.6 million, mainly due to our significant reduction in drilling activity during 2015 in response to the low commodity price environment throughout the year. During 2014 our capital expenditures of \$588.6 million represented an increase of \$107.7 million as compared to 2013 capital expenditures of \$480.9 million due primarily to our high level of drilling activity during 2014.

Our capital expenditure activity related to our continuing operations is summarized in the following table:

	Year Ended December 31,		
	2013	2014	2015
	(In thousands)		
Exploration and development:			
Acquisitions of proved oil and gas properties	\$6,450	\$2,400	\$—
Acquisitions of unproved oil and gas properties	130,113	91,960	12,972
Developmental leasehold costs	461	3,386	767
Development drilling	317,241	398,604	184,393
Exploratory drilling	—	51,725	11,985
Other development costs	26,348	39,282	31,237
	480,613 ⁽¹⁾	587,357 ⁽¹⁾	241,354
Other	260	1,257	1,893
Total	\$480,873 ⁽¹⁾	\$588,614 ⁽¹⁾	\$243,247

(1) Net of reimbursements received from joint venture partner of \$51.5 million and \$28.7 million in 2013 and 2014, respectively.

The timing of most of our capital expenditures is discretionary because we have no material long-term capital expenditure commitments except for contracted drilling and completion services. Consequently, we have a significant degree of flexibility to adjust the level of our capital expenditures as circumstances warrant. We currently expect to spend approximately \$98.0 million in 2016 for development and exploration projects to drill nine wells. Our operating cash flow and, therefore, our capital expenditures are highly dependent on oil and natural gas prices that we realize in 2016. We operate most of our properties and have significant discretion over the amount and timing of our future capital expenditures.

We do not have a specific acquisition budget for 2016 because the timing and size of acquisitions are unpredictable. We intend to use borrowings under our bank credit facility, or other debt or equity financings to the extent available, to finance such acquisitions. The availability and attractiveness of these sources of financing will depend upon a number of factors, some of which will relate to our financial condition and performance and some of which will be beyond our control, such as prevailing interest rates, oil and natural gas prices and other market conditions. Lack of access to the debt or equity markets due to general economic conditions could impede our ability to complete acquisitions.

In March 2015, we issued \$700.0 million of 10% senior secured notes (the "Secured Notes") which are due on March 15, 2020. Interest on the Secured Notes is payable semi-annually on each March 15 and September 15. Net proceeds from the issuance of the Secured Notes of \$683.8 million were used to retire our bank credit facility and for general corporate purposes. We also have outstanding (i) \$376.1 million of 7¾% senior notes (the "2019 Notes") which are due on April 1, 2019 and bear interest which is payable semi-annually on each April 1 and October 1 and (ii) \$194.4 million of 9½% senior notes (the "2020 Notes") which are due on June 15, 2020 and bear interest which is payable semi-annually on each June 15 and December 15. The Secured Notes are secured on a first priority basis equally and ratably with our revolving credit facility, subject to payment priorities in favor of the revolving credit facility by the collateral securing the revolving credit facility, which consists of, among other things, at least 80% of our and our subsidiaries' oil and gas properties. The Secured Notes, the 2019 Notes and 2020 Notes are our general obligations and are guaranteed by all of our subsidiaries. Such subsidiary guarantors are 100% owned and all of the guarantees are full and unconditional and joint and several obligations. There are no restrictions on our ability to obtain funds

from our subsidiaries through dividends or loans. As of December 31, 2015, we had no material assets or operations which are independent of our subsidiaries.

During 2015 we purchased \$23.9 million in principal amount of the 2019 Notes and \$105.6 million in principal amount of the 2020 Notes for an aggregate purchase price of \$42.7 million. The gain of \$82.4 million recognized on the purchase of the 2019 Notes and 2020 Notes and the loss resulting from the write-off of deferred loan costs associated with our prior bank credit facility of \$3.7 million are included in the net gain on extinguishment of debt, which is reported as a component of other income (expense).

In connection with the issuance of the Secured Notes, we entered into a \$50.0 million revolving credit facility with Bank of Montreal and Bank of America, N.A. The revolving credit facility is a four year commitment that matures on March 4, 2019. Indebtedness under the revolving credit facility is secured by substantially all of our and our subsidiaries' assets and is guaranteed by all of our subsidiaries. Borrowings under the revolving credit facility bear interest at our option at either (1) LIBOR plus 2.5% or (2) the base rate (which is the higher of the administrative agent's prime rate, the federal funds rate plus 0.5% or 30 day LIBOR plus 1.0%) plus 1.5%. A commitment fee of 0.5% per annum is payable quarterly on the unused credit line. The revolving credit facility contains covenants that, among other things, restrict the payment of cash dividends and repurchases of common stock, limit the amount of consolidated debt that we may incur and limit our ability to make certain loans, investments and divestitures. The only financial covenants are the maintenance of a current ratio of at least 1.0 to 1.0 and the maintenance of an asset coverage ratio of proved developed reserves to debt outstanding under the revolving credit facility of at least 2.5 to 1.0. We were in compliance with these covenants as of December 31, 2015.

We believe that our cash on hand and cash flow from operations and available borrowings under our bank credit facility is sufficient to fund our 2016 planned operating activities. If our plans or assumptions change or our assumptions prove to be inaccurate, we may be required to seek additional capital, including additional equity or debt financings to replace any liquidity that may be lost from low oil and natural gas prices. We cannot provide any assurance that we will be able to obtain such capital, or if such capital is available, that we will be able to obtain it on acceptable terms.

The following table summarizes our aggregate liabilities and commitments by year of maturity:

	2016	2017	2018	2019	2020	Thereafter	Total
	(In thousands)						
10% senior secured notes	\$—	\$—	\$—	\$—	\$700,000	\$—	\$700,000
7 ³ / ₄ % senior unsecured notes	—	—	—	376,090	—	—	376,090
9 ¹ / ₂ % senior unsecured notes	—	—	—	—	194,367	—	194,367
Interest on debt	117,612	117,612	117,612	95,752	23,046	—	471,634
Operating leases	1,994	2,021	2,060	1,560	1,560	1,560	10,755
Natural gas transportation and treating agreements	2,199	1,780	1,696	690	—	—	6,365
Contracted drilling services	1,593	—	—	—	—	—	1,593
	\$123,398	\$121,413	\$121,368	\$474,092	\$918,973	\$1,560	\$1,760,804

Future interest costs are based upon the effective interest rates of our outstanding senior notes.

We have obligations to incur future payments for dismantlement, abandonment and restoration costs of oil and gas properties. These payments are currently estimated to be incurred primarily after 2020. We record a separate liability for the fair value of these asset retirement obligations, which totaled \$20.1 million as of December 31, 2015.

Federal and State Taxation

We have \$558.7 million in U.S. federal net operating loss carryforwards. The utilization of \$34.7 million of the U.S. federal net operating loss carryforward is limited to approximately \$1.1 million per year pursuant to a prior change of control of an acquired company. Accordingly, as of December 31, 2014, a valuation allowance of \$23.0 million, with a tax effect of \$8.0 million, has been established for

the estimated U.S. federal net operating loss carryforwards that will not be utilized as a result of the change in control. As of December 31, 2015, we have also established a valuation allowance of \$775.3 million, with a tax effect of \$271.4 million, against our other U.S. federal net operating loss carryforwards that are not subject a change in control, due to the uncertainty of generating future taxable income prior to the expiration of the carry-over period. In addition, as of December 31, 2015, we have established a valuation allowance of \$957.7 million, with a tax effect of \$49.8 million, against our Louisiana state net deferred tax assets due to the uncertainty of generating taxable income in the state of Louisiana prior to the expiration of the carry-over period. As of December 31, 2014, we had a valuation allowance of \$742.2 million, with a tax effect of \$38.6 million, against our Louisiana state deferred tax assets.

Future use of our net operating loss carryforwards may be limited in the event that a cumulative change in the ownership of our common stock by more than 50% occurs within a three-year period. Such a change in ownership could result in a substantial portion of our net operating loss carryforwards being eliminated or becoming restricted. We established a rights plan on October 1, 2015 to deter ownership changes that would trigger this limitation.

Our federal income tax returns for the years subsequent to December 31, 2011 remain subject to examination. Our income tax returns in one major state income tax jurisdiction remain subject to examination for the year ended December 31, 2008 and various periods subsequent to December 31, 2010. We currently believe that our significant filing positions are highly certain and that all of our other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on our consolidated financial statements. Therefore, we have not established any significant reserves for uncertain tax positions. Interest and penalties resulting from audits by tax authorities have been immaterial and are included in the provision for income taxes in the consolidated statements of operations.

Critical Accounting Policies

The preparation of financial statements in conformity with accounting principles generally accepted in the United States requires us to make estimates and use assumptions that can affect the reported amounts of assets, liabilities, revenues or expenses.

Successful efforts accounting. We are required to select among alternative acceptable accounting policies. There are two generally acceptable methods for accounting for oil and gas producing activities. The full cost method allows the capitalization of all costs associated with finding oil and natural gas reserves, including certain general and administrative expenses. The successful efforts method allows only for the capitalization of costs associated with developing proven oil and natural gas properties as well as exploration costs associated with successful exploration projects. Costs related to exploration that are not successful are expensed when it is determined that commercially productive oil and gas reserves were not found. We have elected to use the successful efforts method to account for our oil and gas activities and we do not capitalize any of our general and administrative expenses.

Oil and natural gas reserve quantities. The determination of depreciation, depletion and amortization expense is highly dependent on the estimates of the proved oil and natural gas reserves attributable to our properties. The determination of whether impairments should be recognized on our oil and gas properties is also dependent on these estimates, as well as estimates of probable reserves. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be precisely measured. The accuracy of any reserve estimate depends on the quality of available data, production history and engineering and geological interpretation and judgment. Because all reserve estimates are to some degree imprecise, the quantities and timing of oil and natural gas that are ultimately recovered, production and operating costs, the amount and timing of future development expenditures and future oil and natural gas prices may all differ materially from those assumed in these estimates. The

information regarding present value of the future net cash flows attributable to our proved oil and natural gas reserves are estimates only and should not be construed as the current market value of the estimated oil and natural gas reserves attributable to our properties. Thus, such information includes revisions of certain reserve estimates attributable to proved properties included in the preceding year's estimates. Such revisions reflect additional information from subsequent activities, production history of the properties involved and any adjustments in the projected economic life of such properties resulting from changes in product prices. Any future downward revisions could adversely affect our financial condition, our future prospects and the value of our common stock.

Impairment of oil and gas properties. We evaluate our properties on a field area basis for potential impairment when circumstances indicate that the carrying value of an asset may not be recoverable. If impairment is indicated based on a comparison of the asset's carrying value to its undiscounted expected future net cash flows, then it is recognized to the extent that the carrying value exceeds fair value. A significant amount of judgment is involved in performing these evaluations since the results are based on estimated future events. Expected future cash flows are determined using estimated future prices based on market based forward prices applied to projected future production volumes. The projected production volumes are based on the property's proved and risk adjusted probable oil and natural gas reserves estimates at the end of the period. At December 31, 2015, we excluded probable undeveloped reserves from our impairment analysis given our limited capital resources available for future drilling activities. The estimated future cash flows that we use in our assessment of the need for an impairment are based on a corporate forecast which considers forecasts from multiple independent price forecasts. Prices are not escalated to levels that exceed observed historical market prices. Costs are also assumed to escalate at a rate that is based on our historical experience, currently estimated at 2% per annum. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of the average first day of the month historical price for the year. During 2015, our oil and natural gas price outlook declined significantly and our access to capital to develop our proved and probable undeveloped reserves was limited. Accordingly, we recognized impairment charges of \$801.3 million to reduce the capitalized costs of our evaluated oil and natural gas properties. It is reasonably possible that our estimates of undiscounted future net cash flows attributable to its oil and gas properties may change in the future. The primary factors that may affect estimates of future cash flows include future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable oil and gas reserves, results of future drilling activities, future prices for oil and natural gas, and increases or decreases in production and capital costs. As a result of these changes, there may be further impairments in the carrying values of our evaluated oil and gas properties. Specifically, as part of the impairment review performed at December 31, 2015, we observed that a decline in excess of 30% for our future cash flow estimates for our Eagleville field in South Texas could result in an additional impairment being recorded in an amount that could be at least \$130.0 million. In addition, we may recognize additional impairments of our unevaluated oil and gas properties should we determine that we no longer intend to retain these properties for future oil and natural gas development.

Income Taxes. The Company accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

In recording deferred income tax assets, we consider whether it is more likely than not that some portion or all of our deferred income tax assets will be realized in the future. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. We believe that after considering all the available objective evidence, historical and prospective, with greater weight given to historical evidence, we are not able to determine that it is more likely than not that all of our deferred tax assets will be realized. As a result, in 2015 we established an additional valuation allowance of \$775.3 million, with a tax effect of \$271.4 million, for our estimated U.S. federal net operating loss carryforwards and other U.S. federal tax assets and an additional valuation allowance of \$215.5 million, with a tax effect of \$11.2 million, for our estimated Louisiana state net operating loss carryforwards that are not expected to be utilized due to the uncertainty of generating taxable income prior to the expiration of the respective U.S. federal and Louisiana state carry-over periods. We will continue to assess the valuation allowance against deferred tax assets considering all available information obtained in future reporting periods.

Stock-based compensation. We follow the fair value based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period.

Recent accounting pronouncements. In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under existing generally accepted accounting principles. This new standard is based upon the principal that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted beginning with periods after December 15, 2016 and entities have the option of using either a full retrospective or modified approach to adopt ASU 2014-09. We are currently evaluating the new guidance and have not determined the impact this standard may have on our financial statements or decided upon the method of adoption.

In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and sets rules for how this information should be disclosed in the financial statements. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and interim periods thereafter. Early adoption is permitted. We have elected to not adopt ASU 2014-15 early and do not expect adoption of ASU 2014-15 to have any impact on our consolidated financial condition, results of operations or cash flows.

Related Party Transactions

Along with M. Jay Allison, our Chairman and CEO, and Roland O. Burns, our President, Chief Financial Officer and a director, we formed an entity in 2010 in which we jointly owned and operated a private airplane. The entity was owned 80% by us and 10% by each of Messrs. Allison and Burns. Each party funded their respective share of the acquisition costs of the airplane in exchange for their ownership interest. This arrangement was approved by our audit committee and board of directors. In January 2015, we acquired from Messrs. Allison and Burns their collective 20%

interest in the entity for aggregate consideration of \$1,680,000, which amount was based upon the then fair market value of the airplane (the only asset owned by the entity). The airplane is leased to and managed by a third party operator. The

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airplane, which is intended to be used primarily for company business, also provides charter services to third parties. The termination of this related party relationship was approved by our audit committee and the board of directors in accordance with our policy on related party transactions. We have not entered into any other business transactions with our significant stockholders or any other related parties.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Oil and Natural Gas Prices

Our financial condition, results of operations and capital resources are highly dependent upon the prevailing market prices of oil and natural gas. These commodity prices are subject to wide fluctuations and market uncertainties due to a variety of factors that are beyond our control. Factors influencing oil and natural gas prices include the level of global demand for oil, the foreign supply of oil and natural gas, the establishment of and compliance with production quotas by oil exporting countries, weather conditions which determine the demand for natural gas, the price and availability of alternative fuels and overall economic conditions. It is impossible to predict future oil and natural gas prices with any degree of certainty. Sustained weakness in oil and natural gas prices may adversely affect our financial condition and results of operations, and may also reduce the amount of oil and natural gas reserves that we can produce economically. Any reduction in our oil and natural gas reserves, including reductions due to price fluctuations, can have an adverse effect on our ability to obtain capital for our exploration and development activities. Similarly, any improvements in oil and natural gas prices can have a favorable impact on our financial condition, results of operations and capital resources. Based on our oil and natural gas production in 2015, a \$1.00 change in the price per barrel of oil would have resulted in a change in our cash flow for such period by approximately \$3.0 million and a \$0.10 change in the price per Mcf of natural gas would have changed our cash flow by approximately \$4.6 million.

Interest Rates

At December 31, 2015, we had principal amount of \$1.3 billion of long-term debt outstanding. Of this amount, \$700.0 million bears interest at a fixed rate of 10%, \$376.1 million bears interest at a fixed rate of $7\frac{3}{4}\%$ and \$194.4 million bears interest at a fixed rate of $9\frac{1}{2}\%$. The fair market value of our fixed rate debt as of December 31, 2015 was \$428.8 million based on the market price of approximately 34% of the face amount. At December 31, 2015, we had no borrowings outstanding under our bank credit facility, which is subject to variable rates of interest that are tied to LIBOR or a corporate base rate, at our option. We had no interest rate derivative financial instruments in 2015 or at December 31, 2015.

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

Our consolidated financial statements are included on pages F-1 to F-30 of this report.

We have prepared these financial statements in conformity with generally accepted accounting principles. We are responsible for the fairness and reliability of the financial statements and other financial data included in this report. In the preparation of the financial statements, it is necessary for us to make informed estimates and judgments based on currently available information on the effects of certain events and transactions.

Our independent public accountants, Ernst & Young LLP, are engaged to audit our financial statements and to express an opinion thereon. Their audit is conducted in accordance with auditing standards generally accepted in the United States to enable them to report whether the financial statements present fairly, in all material respects, our financial position and results of operations in accordance with accounting principles generally accepted in the United States.

The audit committee of our board of directors is comprised of three directors who are not our employees. This committee meets periodically with our independent public accountants and management.

Our independent public accountants have full and free access to the audit committee to meet, with and without management being present, to discuss the results of their audits and the quality of our financial reporting.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

ITEM 9A. CONTROLS AND PROCEDURES

Evaluation of Controls and Procedures. Disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended, or the Exchange Act) are designed to provide reasonable assurance that information required to be disclosed in reports we file or submit under the Exchange Act 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 Chief Executive Officer and Chief Financial Officer, as appropriate to allow timely decisions regarding required disclosures.

We performed an evaluation of the effectiveness of our disclosure controls and procedures as of December 31, 2015. The evaluation was performed with the participation of senior management of each business segment and key corporate functions, and under the supervision of the Chief Executive Officer and Chief Financial Officer.

Based on our evaluation of our disclosure controls and procedures, our chief executive officer and chief financial officer concluded that our disclosure controls and procedures were effective as of December 31, 2015 to provide reasonable assurance that information required to be disclosed by us in the reports filed or submitted by us under the Securities Exchange Act of 1934 is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms, and to provide reasonable assurance that information required to be disclosed by us is accumulated and communicated to our management, including our chief executive officer and chief financial officer, as appropriate, to allow timely decisions regarding required disclosure.

Changes in Internal Control over Financial Reporting. There were no changes in our internal control over financial reporting during the quarter ended December 31, 2015 that materially affected or are reasonably likely to materially affect our internal control over financial reporting.

Management's Report on Internal Control over Financial Reporting. We are responsible for establishing and maintaining adequate internal control over financial reporting for the Company. In order to evaluate the effectiveness of internal control over financial reporting, as required by Section 404 of the Sarbanes-Oxley Act, we conducted an assessment, including testing, using the criteria in Internal Control — Integrated Framework, issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Our system of internal control over financial reporting is designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate. As of December 31, 2015, we assessed the effectiveness of the Company's internal control over financial reporting based on the COSO criteria, and based on that assessment we determined that the Company maintained effective internal control over financial reporting as of December 31, 2015.

Ernst & Young LLP, the independent registered public accounting firm that audited the consolidated financial statements of the Company included in this Annual Report on Form 10-K, has issued an attestation report on the effectiveness of the Company's internal control over financial reporting as of December 31, 2015. The report, which expresses an unqualified opinion on the effectiveness of the Company's internal control over financial reporting as of December 31, 2015, is included below.

Report of Independent Registered Public Accounting Firm

The Board of Directors and Stockholders

Comstock Resources, Inc.

We have audited Comstock Resources, Inc. and subsidiaries' internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) (the COSO criteria). Comstock Resources, Inc. and subsidiaries' management is responsible for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting included in the accompanying Management's Report on Internal Control Over Financial Reporting. Our responsibility is to express an opinion on the company's internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, testing and evaluating the design and operating effectiveness of internal control based on the assessed risk, and performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

A company's internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with generally accepted accounting principles. A company's internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the company; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with generally accepted accounting principles, and that receipts and expenditures of the company are being made only in accordance with authorizations of management and directors of the company; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the company's assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, Comstock Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on the COSO criteria.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated balance sheets of Comstock Resources, Inc. and subsidiaries as of December 31, 2014 and 2015, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2015 and our report dated February 26, 2016 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP
Dallas, Texas

February 26, 2016

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ITEM 9B. OTHER INFORMATION

None.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The information required by this item is incorporated herein by reference to "Business – Directors and Executive Officers" in this Form 10-K and to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2015.

Code of Ethics. We have adopted a Code of Business Conduct and Ethics that is applicable to all of our directors, officers and employees as required by New York Stock Exchange rules. We have also adopted a Code of Ethics for Senior Financial Officers that is applicable to our Chief Executive Officer and Senior Financial Officers. Both the Code of Business Conduct and Ethics and Code of Ethics for Senior Financial Officers may be found on our website at www.comstockresources.com. Both of these documents are also available, without charge, to any stockholder upon request to: Comstock Resources, Inc., Attn: Investor Relations, 5300 Town and Country Blvd., Suite 500, Frisco, Texas 75034, (972) 668-8800. We intend to disclose any amendments or waivers to these codes that apply to our Chief Executive Officer and senior financial officers on our website in accordance with applicable SEC rules. Please see the definitive proxy statement for our 2016 annual meeting, which will be filed with the SEC within 120 days of December 31, 2015, for additional information regarding our corporate governance policies.

ITEM 11. EXECUTIVE COMPENSATION

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2015.

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED STOCKHOLDER MATTERS

The following table summarizes certain information regarding our equity compensation plans as of December 31, 2015:

Number of securities to be issued upon exercise of	Weighted average exercise price of outstanding options, warrants and rights	Number of securities authorized for future issuance under equity compensation plans (including outstanding options, warrants and rights)
1,458,823 ⁽¹⁾	\$33.22	957,845

Equity compensation plans approved
by stockholders

(1) Includes performance share unit awards equivalent to 1,400,173 shares that would be issuable based upon achievement of the maximum awards under the terms of the performance share unit awards.

We do not have any equity compensation plans that were not approved by stockholders.

Further information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2015.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2015.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

The information required by this item is incorporated herein by reference to our definitive proxy statement which will be filed with the SEC within 120 days after December 31, 2015.

PART IV

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) Financial Statements:

1. The following consolidated financial statements and notes of Comstock Resources, Inc. are included on Pages F-2 to F-30 of this report:

<u>Report of Independent Registered Public Accounting Firm</u>	F-2
<u>Consolidated Balance Sheets as of December 31, 2014 and 2015</u>	F-3
<u>Consolidated Statements of Operations for the Years Ended December 31, 2013, 2014 and 2015</u>	F-4
<u>Consolidated Statements of Comprehensive Income (Loss) for the Years Ended December 31, 2013, 2014 and 2015</u>	F-5
<u>Consolidated Statements of Stockholders' Equity (Deficit) for the Years Ended December 31, 2013, 2014 and 2015</u>	F-6
<u>Consolidated Statements of Cash Flows for the Years Ended December 31, 2013, 2014 and 2015</u>	F-7
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Notes to Consolidated Financial Statements

2. All financial statement schedules are omitted because they are not applicable, or are immaterial or the required information is presented in the consolidated financial statements or the related notes.

(b) Exhibits:

The exhibits to this report required to be filed pursuant to Item 15(c) are listed below.

Exhibit No.	Description
3.1	Restated Articles of Incorporation (incorporated by reference to Exhibit 3.1 to our Annual Report on Form 10-K for the year ended December 31, 1995).
3.2	Certificate of Amendment to the Restated Articles of Incorporation dated July 1, 1997 (incorporated by reference to Exhibit 3.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 1997).
3.3	Certificate of Amendment to the Restated Articles of Incorporation dated May 19, 2009 (incorporated by reference to Exhibit 3.1 to our Registration Statement on Form S-3 dated October 5, 2009).
3.4	Amended and Restated Bylaws (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated August 21, 2014).

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Exhibit No.	Description
3.5	Certificate of Designation of Series C Junior Participating Preferred Stock of Comstock Resources, Inc. (incorporated by reference to Exhibit 3.1 to our Current Report on Form 8-K dated October 1, 2015).
4.1	Indenture dated February 25, 2004 between Comstock Resources, Inc., the guarantors and The Bank of New York Trust Company, N.A., Trustee for debt securities issued by Comstock Resources, Inc. (incorporated by reference to Exhibit 4.6 to our Annual Report on Form 10-K for the year ended December 31, 2003).
4.2	Third Supplemental Indenture dated March 14, 2011 between Comstock Resources, Inc., the guarantors and The Bank of New York Mellon Trust Company, N.A., for the 7 ³ / ₄ % Senior Notes due 2019 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 14, 2011).
4.3	Fourth Supplemental Indenture dated June 5, 2012 between Comstock Resources, Inc., the guarantors and The Bank of New York Mellon Trust Company, N.A., for the 9 ¹ / ₂ % Senior Notes due 2020 (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated June 7, 2012).
4.4	Indenture dated March 13, 2015 between Comstock Resources, Inc., the guarantors and The Bank of New York Mellon Trust Company, N.A., Trustee for senior secured debt securities issued by Comstock Resources, Inc. (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated March 13, 2015).
4.5	Rights Agreement dated October 1, 2015 between Comstock Resources, Inc. and American Stock Transfer & Trust Company LLC, as rights agent (incorporated by reference to Exhibit 4.1 to our Current Report on Form 8-K dated October 1, 2015).
10.1#	Amended and Restated Employment Agreement dated February 24, 2014 by and between Comstock Resources, Inc. and M. Jay Allison (incorporated by reference to Exhibit 10.1 to our Annual Report on Form 10-K for the year ended December 31, 2013).
10.2#	Amended and Restated Employment Agreement dated February 24, 2014 by and between Comstock Resources, Inc. and Roland O. Burns (incorporated by reference to Exhibit 10.2 to our Annual Report on Form 10-K for the year ended December 31, 2013).
10.3#	Employment Agreement dated February 23, 2015 by and between Comstock Resources, Inc. and Mack D. Good (incorporated by reference to Exhibit 10.3 to our Annual Report on Form 10-K for the

year ended December 31, 2015).

- 10.4#* Comstock Resources, Inc. 2009 Long-term Incentive Plan Amended and Restated Effective as of May 7, 2015.
- 10.5 Credit Agreement dated March 4, 2015 among Comstock Resources, Inc., as the borrower, the lenders from time to time thereto, and Bank of Montreal as administrative agent and issuing bank (incorporated by reference to Exhibit 10.2 to our Current Report on Form 8-K dated March 4, 2015).
- 10.6 Lease between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. dated May 6, 2004 (incorporated by reference to Exhibit 10.24 to our Annual Report on Form 10-K for the year ended December 31, 2004).
- 10.7 First Amendment to the Lease Agreement dated August 25, 2005, between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.20 to our Annual Report on Form 10-K for the year ended December 31, 2005).
- 10.8 Second Amendment to the Lease Agreement dated October 15, 2007 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.10 to our Annual Report on Form 10-K for the year ended December 31, 2008).
- 10.9 Third Amendment to the Lease Agreement dated September 30, 2008 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.11 to our Annual Report on Form 10-K for the year ended December 31, 2008).
- 10.10 Fourth Amendment to the Lease Agreement dated May 8, 2009 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.2 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2009).

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Exhibit No.	Description
10.11	Fifth Amendment to the Lease Agreement dated June 15, 2011 between Stonebriar I Office Partners, Ltd. and Comstock Resources, Inc. (incorporated by reference to Exhibit 10.1 to our Quarterly Report on Form 10-Q for the quarter ended June 30, 2011).
10.12	Base Contract for Sale and Purchase of Natural Gas between Comstock Oil & Gas-Louisiana, LLC and BP Energy Company dated November 7, 2008, as amended by Third Amended and Restated Special Provisions dated January 5, 2010 (incorporated by reference to Exhibit 10.14 to our Annual Report on Form 10-K for the year ended December 31, 2009).
21*	Subsidiaries of the Company.
23.1*	Consent of Ernst & Young LLP.
23.2*	Consent of Independent Petroleum Engineers.
31.1*	Chief Executive Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
31.2*	Chief Financial Officer certification under Section 302 of the Sarbanes-Oxley Act of 2002.
32.1+	Chief Executive Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
32.2+	Chief Financial Officer certification under Section 906 of the Sarbanes-Oxley Act of 2002.
99.1*	Report of Independent Petroleum Engineers on Proved Reserves as of December 31, 2015.
101.INS*	XBRL Instance Document
101.SCH*	XBRL Schema Document
101.CAL*	XBRL Calculation Linkbase Document
101.LAB*	XBRL Labels Linkbase Document

101.PRE* XBRL Presentation Linkbase Document

101.DEF* XBRL Definition Linkbase Document

*Filed herewith.

+Furnished herewith.

#Management contract or compensatory plan document.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

COMSTOCK RESOURCES,
INC.

By: /s/ M. JAY ALLISON
M. Jay Allison

Chief Executive Officer
(Principal Executive Officer)

Date: February 26, 2016

Pursuant to the requirements of the Securities Exchange Act of 1934, this report has been signed below by the following persons on behalf of the registrant and in the capacities and on the dates indicated.

/s/ M. JAY ALLISON M. Jay Allison	Chief Executive Officer and Chairman of the Board of Directors (Principal Executive Officer)	February 26, 2016
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/s/ ROLAND O. BURNS Roland O. Burns	President, Chief Financial Officer, Secretary and Director (Principal Financial and Accounting Officer)	February 26, 2016
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/s/ ELIZABETH B. DAVIS Elizabeth B. Davis	Director	February 26, 2016
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/s/ DAVID K. LOCKETT David K. Lockett	Director	February 26, 2016
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/s/ CECIL E. MARTIN, JR. Cecil E. Martin, Jr.	Director	February 26, 2016
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/s/ FREDERIC D. SEWELL Frederic D. Sewell	Director	February 26, 2016
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/s/ DAVID W. SLEDGE
David W. Sledge

Director

February 26, 2016

/s/ JIM L. TURNER
Jim L. Turner

Director

February 26, 2016

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

The Board of Directors and Stockholders

Comstock Resources, Inc.

We have audited the accompanying consolidated balance sheets of Comstock Resources, Inc. and subsidiaries as of December 31, 2014 and 2015, and the related consolidated statements of operations, comprehensive income (loss), stockholders' equity (deficit) and cash flows for each of the three years in the period ended December 31, 2015. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, the financial statements referred to above present fairly, in all material respects, the consolidated financial position of Comstock Resources, Inc. and subsidiaries at December 31, 2014 and 2015, and the consolidated results of their operations and their cash flows for each of the three years in the period ended December 31, 2015, in conformity with accounting principles generally accepted in the United States.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), Comstock Resources, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (2013 framework) and our report dated February 26, 2016 expressed an unqualified opinion thereon.

/s/ ERNST & YOUNG LLP

Dallas, Texas

February 26, 2016

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED BALANCE SHEETS

As of December 31, 2014 and 2015

	December 31,	
	2014	2015
	(In thousands)	
ASSETS		
Cash and Cash Equivalents	\$2,071	\$ 134,006
Accounts Receivable:		
Oil and gas sales	32,849	15,241
Joint interest operations	16,192	3,552
Derivative Financial Instruments	—	1,446
Other Current Assets	10,105	1,993
Total current assets	61,217	156,238
Property and Equipment:		
Unevaluated oil and gas properties	201,459	84,144
Oil and gas properties, successful efforts method	4,282,088	4,332,222
Other	19,630	19,521
Accumulated depreciation, depletion and amortization	(2,305,008)	(3,397,467)
Net property and equipment	2,198,169	1,038,420
Other Assets	5,160	1,192
	\$2,264,546	\$ 1,195,850

LIABILITIES AND STOCKHOLDERS' EQUITY (DEFICIT)

Accounts Payable	\$ 117,329	\$ 57,276
Accrued Expenses	44,842	38,444
Total current liabilities	162,171	95,720
Long-term Debt	1,060,654	1,249,330
Deferred Income Taxes Payable	154,547	1,965
Reserve for Future Abandonment Costs	14,900	20,093
Other Non-Current Liabilities	2,002	—
Total liabilities	1,394,274	1,367,108
Commitments and Contingencies		

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Stockholders' Equity (Deficit):

Common stock—\$0.50 par, 75,000,000 shares authorized, 46,858,415 and 47,720,176 shares issued and outstanding at December 31, 2014 and 2015, respectively	23,429	23,860
Additional paid-in capital	480,434	485,582
Accumulated earnings (deficit)	366,409	(680,700)
Total stockholders' equity (deficit)	870,272	(171,258)
	\$2,264,546	\$1,195,850

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF OPERATIONS

For the Years Ended December 31, 2013, 2014 and 2015

	2013	2014	2015
	(In thousands, except per share amounts)		
Natural gas sales	\$ 188,453	\$ 165,461	\$ 109,753
Oil sales	231,837	389,770	142,669
Total oil and gas sales	420,290	555,231	252,422
Operating expenses:			
Production taxes	14,524	23,797	10,286
Gathering and transportation	17,245	12,897	14,298
Lease operating	52,844	60,283	64,502
Exploration	33,423	19,403	70,694
Depreciation, depletion and amortization	337,134	378,275	321,323
General and administrative, net	34,767	32,379	23,541
Impairment of oil and gas properties	652	60,268	801,347
Loss on sale of oil and gas properties	2,033	—	112,085
Total operating expenses	492,622	587,302	1,418,076
Operating loss	(72,332)	(32,071)	(1,165,654)
Other income (expenses):			
Gain on sale of marketable securities	7,877	—	—
Gain (loss) from derivative financial instruments	(8,388)	8,175	2,676
Net gain (loss) on extinguishment of debt	(17,854)	—	78,741
Other income	1,059	727	1,275
Interest expense	(73,242)	(58,631)	(118,592)
Total other income (expenses)	(90,548)	(49,729)	(35,900)
Loss from continuing operations before income taxes	(162,880)	(81,800)	(1,201,554)
Benefit from income taxes	56,157	24,689	154,445
Loss from continuing operations	(106,723)	(57,111)	(1,047,109)
Income from discontinued operations, net of income taxes	147,752	—	—
Net income (loss)	\$41,029	\$(57,111)	\$(1,047,109)

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Net income (loss) per share:				
Basic and diluted	-loss from continuing operations	\$ (2.22)	\$ (1.24)	\$ (22.71)
	-income from discontinued operations	3.07	—	—
	-net income (loss)	\$ 0.85	\$ (1.24)	\$ (22.71)
Dividends per common share		\$ 0.375	\$ 0.500	\$ —
Basic and diluted weighted average shares outstanding		46,553	46,547	46,113

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF COMPREHENSIVE INCOME (LOSS)

For the Years Ended December 31, 2013, 2014 and 2015

	2013	2014	2015
	(In thousands)		
Net income (loss)	\$41,029	\$(57,111)	\$(1,047,109)
Other comprehensive income (loss):			
Realized gains on marketable securities reclassified to gain on sale of marketable securities, net of a benefit from income taxes of \$2,757 in 2013	(5,120)	—	—
Unrealized gains on marketable securities, net of a provision for income taxes of \$377 in 2013	702	—	—
Other comprehensive loss	(4,418)	—	—
Total comprehensive income (loss)	\$36,611	\$(57,111)	\$(1,047,109)

The accompanying notes are an integral part of these statements.

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COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF STOCKHOLDERS' EQUITY (DEFICIT)

For the Years Ended December 31, 2013, 2014 and 2015

	Common Shares	Common Stock- Par Value	Additional Paid-in Capital	Accumulated Earnings (Deficit)	Accumulated Other Comprehensive Income	Total
(In thousands)						
Balance at December 31, 2012	48,409	\$ 24,204	\$ 480,595	\$ 424,317	\$ 4,418	\$ 933,534
Stock-based compensation	14	7	12,778	—	—	12,785
Tax withholdings related to stock grants	(111)	(55)	(1,625)	—	—	(1,680)
Excess income taxes from stock-based compensation	—	—	(2,016)	—	—	(2,016)
Repurchases of common stock	(631)	(316)	(8,916)	—	—	(9,232)
Net income	—	—	—	41,029	—	41,029
Other comprehensive loss	—	—	—	—	(4,418)	(4,418)
Dividends paid	—	—	—	(17,997)	—	(17,997)
Balance at December 31, 2013	47,681	23,840	480,816	447,349	—	952,005
Stock-based compensation	308	154	10,543	—	—	10,697
Tax withholdings related to stock grants	(131)	(65)	(2,284)	—	—	(2,349)
Excess income taxes from stock-based compensation	—	—	(1,055)	—	—	(1,055)
Repurchases of common stock	(1,000)	(500)	(7,586)	—	—	(8,086)
Net loss	—	—	—	(57,111)	—	(57,111)
Dividends paid	—	—	—	(23,829)	—	(23,829)
Balance at December 31, 2014	46,858	23,429	480,434	366,409	—	870,272
Stock-based compensation	940	470	7,679	—	—	8,149
Tax withholdings related to stock grants	(78)	(39)	(487)	—	—	(526)
Excess income taxes from stock-based compensation	—	—	(2,044)	—	—	(2,044)
Net loss	—	—	—	(1,047,109)	—	(1,047,109)
Balance at December 31, 2015	47,720	\$ 23,860	\$ 485,582	\$ (680,700)	\$ —	\$ (171,258)

The accompanying notes are an integral part of these statements.

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COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

CONSOLIDATED STATEMENTS OF CASH FLOWS

For the Years Ended December 31, 2013, 2014 and 2015

	2013	2014	2015
	(In thousands)		
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income (loss)	\$41,029	\$(57,111)	\$(1,047,109)
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Income from discontinued operations	(147,752)	—	—
Loss (gain) on sale of assets	(5,844)	—	112,085
Deferred income taxes	(56,291)	(24,677)	(155,249)
Dry hole costs, leasehold impairments and other exploration costs	32,984	19,003	70,694
Impairment of oil and gas properties	652	60,268	801,347
Depreciation, depletion and amortization	337,134	378,275	321,323
(Gain) loss on derivative financial instruments	8,388	(8,175)	(2,676)
Cash settlements of derivative financial instruments	2,293	9,145	1,230
Net loss (gain) on extinguishment of debt	17,854	—	(78,741)
Amortization of debt discount, premium and issuance costs	6,074	4,097	5,144
Stock-based compensation	12,785	10,697	8,149
Excess income taxes from stock-based compensation	2,016	1,055	2,044
Decrease (increase) in accounts receivable	(12,674)	2,221	30,248
Decrease (increase) in other current assets	3,459	(7,366)	8,112
Increase (decrease) in accounts payable and accrued expenses	26,887	13,552	(46,515)
Net cash provided by continuing operations	268,994	400,984	30,086
Net cash used for discontinued operations	(7,715)	—	—
Net cash provided by operating activities	261,279	400,984	30,086
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures	(422,244)	(634,787)	(264,210)
Proceeds from sales of oil and gas properties	174	—	102,485
Proceeds from sales of marketable securities	13,392	—	—
Net cash used for continuing operations	(408,678)	(634,787)	(161,725)
Cash flow from investing activities of discontinued operations:			
Capital expenditures	(101,037)	—	—
Proceeds from sale of oil and gas properties	823,072	—	—
Net cash provided by discontinued operations	722,035	—	—
Net cash provided by (used for) investing activities	313,357	(634,787)	(161,725)
CASH FLOWS FROM FINANCING ACTIVITIES:			

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Borrowings	305,000	370,750	790,000
Principal payments on debt	(835,000)	(100,000)	(507,655)
Costs related to extinguishment of debt	(12,471)	—	—
Debt issuance costs	(2,744)	(2,524)	(16,201)
Tax withholding related to stock grants	(1,680)	(2,349)	(526)
Repurchases of common stock	(9,232)	(8,086)	—
Excess income taxes from stock-based compensation	(2,016)	(1,055)	(2,044)
Dividends paid	(17,997)	(23,829)	—
Net cash provided by (used for) financing activities	(576,140)	232,907	263,574
Net increase (decrease) in cash and cash equivalents	(1,504)	(896)	131,935
Cash and cash equivalents, beginning of the year	4,471	2,967	2,071
Cash and cash equivalents, end of the year	\$2,967	\$2,071	\$134,006

The accompanying notes are an integral part of these statements.

COMSTOCK RESOURCES, INC. AND SUBSIDIARIES

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(1) Summary of Significant Accounting Policies

Accounting policies used by Comstock Resources, Inc. and subsidiaries reflect oil and natural gas industry practices and conform to accounting principles generally accepted in the United States of America.

Basis of Presentation and Principles of Consolidation

Comstock Resources, Inc. and its subsidiaries are engaged in oil and natural gas exploration, development and production, and the acquisition of producing oil and natural gas properties. The Company's operations are primarily focused in Texas, Louisiana and Mississippi. The consolidated financial statements include the accounts of Comstock Resources, Inc. and its wholly owned or controlled subsidiaries (collectively, "Comstock" or the "Company"). All significant intercompany accounts and transactions have been eliminated in consolidation. The Company accounts for its undivided interest in oil and gas properties using the proportionate consolidation method, whereby its share of assets, liabilities, revenues and expenses are included in its financial statements.

Reclassifications

Certain reclassifications have been made to prior periods' financial statements, consisting primarily of reclassifications of the presentation of debt issuance costs as a reduction in long term debt and presentation of current deferred income taxes as non-current due to the early adoption of new accounting standards.

Use of Estimates in the Preparation of Financial Statements

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities at the date of the financial statements, and the reported amounts of revenues and expenses during the reporting period. Actual amounts could differ from those estimates. Changes in the future estimated oil and natural gas reserves or the estimated future cash flows attributable to the reserves that are utilized for impairment analyses could have a significant impact on the future results of operations.

Concentration of Credit Risk and Accounts Receivable

Financial instruments that potentially subject the Company to a concentration of credit risk consist principally of cash and cash equivalents, accounts receivable and derivative financial instruments. The Company places its cash with high credit quality financial institutions and its derivative financial instruments with financial institutions and other firms that management believes have high credit ratings. Substantially all of the Company's accounts receivable are due from either purchasers of oil and gas or participants in oil and gas wells for which the Company serves as the operator. Generally, operators of oil and gas wells have the right to offset future revenues against unpaid charges related to operated wells. Oil and gas sales are generally unsecured. The Company's policy is to assess the collectability of its receivables based upon their age, the credit quality of the purchaser or participant and the potential for revenue offset. The Company has not had any significant credit losses in the past and believes its accounts receivable are fully collectible. Accordingly, no allowance for doubtful accounts has been provided.

Marketable Securities

During 2013, the Company sold 600,000 shares of Stone Energy Corporation common stock for proceeds of \$13.4 million. Realized gains before income taxes of \$7.9 million on these sales during 2013 are included in gain on sale of marketable securities in the consolidated statements of operations.

Other Current Assets

Other current assets at December 31, 2014 and 2015 consist of the following:

	As of December 31,	
	2014	2015
	(In thousands)	
Settlements receivable on derivative financial instruments	\$7,890	\$—
Pipe and oil field equipment inventory	1,379	1,198
Other	836	795
	\$10,105	\$1,993

Fair Value Measurements

Certain accounts within the Company's consolidated balance sheets are required to be measured at fair value on a recurring basis. These include cash equivalents held in bank accounts and derivative financial instruments in the form of oil and natural gas price swap agreements. Fair value is defined as the price that would be received to sell an asset or paid to transfer a liability (an exit price) in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date. A three-level hierarchy is followed for disclosure to show the extent and level of judgment used to estimate fair value measurements:

Level 1 – Inputs used to measure fair value are unadjusted quoted prices that are available in active markets for the identical assets or liabilities as of the reporting date.

Level 2 – Inputs used to measure fair value, other than quoted prices included in Level 1, are either directly or indirectly observable as of the reporting date through correlation with market data, including quoted prices for similar assets and liabilities in active markets and quoted prices in markets that are not active. Level 2 also includes assets and liabilities that are valued using models or other pricing methodologies that do not require significant judgment since the input assumptions used in the models, such as interest rates and volatility factors, are corroborated by readily observable data from actively quoted markets for substantially the full term of the financial instrument.

Level 3 – Inputs used to measure fair value are unobservable inputs that are supported by little or no market activity and reflect the use of significant management judgment. These values are generally determined using pricing models for which the assumptions utilize management's estimates of market participant assumptions.

The Company's cash and cash equivalents valuation is based on Level 1 measurements. The Company's oil and natural gas price swap agreements were not traded on a public exchange, and their value is determined utilizing a discounted cash flow model based on inputs that are readily available in public markets and, accordingly, the valuation of these swap agreements is categorized as a Level 2 measurement.

The following table summarizes financial assets accounted for at fair value as of December 31, 2015:

	Carrying Value Measured at Fair Value at December 31, 2015		
	Level 1	Level 2	
	(In thousands)		
Assets measured at fair value on a recurring basis:			
Cash and cash equivalents	\$ 134,006	\$ 134,006	\$—
Derivative financial instruments	1,446	—	1,446
Total assets	\$ 135,452	\$ 134,006	\$ 1,446

At December 31, 2015, the Company had natural gas price swap agreements covering approximately 1.8 Bcf of natural gas to be produced in 2016 with a fair value of \$1.4 million. The Company has recognized an asset for this amount and has recognized a corresponding gain representing the change in fair value of its natural gas swaps as a component of other income (expense). The Company had no derivative financial instruments outstanding at December 31, 2014.

The following table presents the carrying amounts and estimated fair value of the Company's long-term debt as of December 31, 2014 and 2015:

	2014	2015
	(In thousands)	
Fixed rate debt:		
Principal amount	\$ 700,000	\$ 1,270,457
Discount or premium	(4,555)	(1,457)
Carrying value	\$ 695,445	\$ 1,269,000
Fair Value	\$ 453,000	\$ 428,767
Variable rate debt:		
Carrying value	\$ 375,000	\$—
Fair value	\$ 375,000	\$—

The fair market value of the Company's fixed rate debt was based on quoted prices as of December 31, 2014 and 2015, a Level 2 measurement. The fair value of the floating rate debt outstanding at December 31, 2014 approximated its carrying value, a Level 2 measurement.

Property and Equipment

The Company follows the successful efforts method of accounting for its oil and gas properties. Costs incurred to acquire oil and gas leasehold are capitalized. Acquisition costs for proved oil and gas properties, costs of drilling and equipping productive wells, and costs of unsuccessful development wells are capitalized and amortized on an

equivalent unit-of-production basis over the life of the remaining related oil and gas reserves. Equivalent units are determined by converting oil to natural gas at the ratio of one barrel of oil for six thousand cubic feet of natural gas. This conversion ratio is not based on the price of oil or natural gas, and there may be a significant difference in price between an equivalent volume of oil versus natural gas. Amortization is calculated at the field level. The estimated future costs of dismantlement, restoration, plugging and abandonment of oil and gas properties and related facilities disposal are capitalized when asset retirement obligations are incurred and amortized as part of depreciation, depletion and amortization expense. The costs of unproved properties which are determined to be productive are transferred to proved oil and gas properties and amortized on an equivalent unit-of-production basis. Exploratory expenses, including geological and geophysical expenses and delay rentals

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for unevaluated oil and gas properties, are charged to expense as incurred. Unproved oil and gas properties are periodically assessed for impairment on a property by property basis, and any impairment in value is charged to exploration expense. During 2013, 2014 and 2015, impairment charges of \$33.0 million, \$0.5 million and \$68.9 million, respectively, were recognized in exploration expense related to certain leases that the Company no longer expects to drill on. Exploratory drilling costs are initially capitalized as unproved property but charged to expense if and when the well is determined not to have found commercial quantities of proved oil and gas reserves. Exploratory drilling costs are evaluated within a one-year period after the completion of drilling.

The Company periodically assesses the need for an impairment of the costs capitalized for its evaluated oil and gas properties on a property or cost center basis. If impairment is indicated based on undiscounted expected future cash flows attributable to the property, then a provision for impairment is recognized to the extent that net capitalized costs exceed the estimated fair value of the property. The Company determines the fair values of its oil and gas properties using a discounted cash flow model and proved and risk-adjusted probable reserves. Undrilled acreage is valued based on sales transactions in comparable areas. At December 31, 2015, the Company excluded probable undeveloped reserves from its impairment analysis given the Company's limited capital resources available for future drilling activities. Significant Level 3 assumptions associated with the calculation of discounted future cash flows included in the cash flow model include management's outlook for oil and natural gas prices, production costs, capital expenditures, and future production as well as estimated proved reserves and risk-adjusted probable reserves. Management's oil and natural gas price outlook is developed based on third-party longer-term price forecasts as of each measurement date. The expected future net cash flows are discounted using an appropriate discount rate in determining a property's fair value. The oil and natural gas prices used for determining asset impairments will generally differ from those used in the standardized measure of discounted future net cash flows because the standardized measure requires the use of an average price based on the first day of each month of the preceding year and is limited to proved reserves.

In 2015, reductions to management's oil and natural gas price outlook resulted in indications of impairment of the Company's oil properties in South Texas and Mississippi, and certain of its natural gas properties in Texas and Louisiana. The following table presents the fair value and impairments recorded by the Company in the third quarter and fourth quarter of 2015, as well as the average oil price per barrel and gas price per thousand cubic feet over the life of the properties and the applicable discount rates utilized in the Company's assessments:

	Fair		Management's Price Outlook		Annual Discount Rate
	Value	Impairment	Oil	Gas	
	(In thousands)		(Per barrel)	(Per Mcf)	
Impairments recorded at September 30, 2015:					
Oil properties	\$330,257	\$405,308	\$73.70	\$4.04	10%-20%
Natural gas properties	\$61,625	\$139,406	\$75.91	\$3.91	10%-20%
Impairments recorded at December 31, 2015:					
Oil properties	\$3,030	\$16,036	\$73.48		10%-20%
Natural gas properties	\$123,926	\$238,210	\$70.76	\$3.74	10%-20%

In the aggregate we recognized impairments of \$801.3 million related to our evaluated oil and gas properties in 2015. In 2014, the Company recognized impairment charges of \$60.3 million on certain of its oil and gas properties which had a fair value of \$18.0 million.

It is reasonably possible that the Company's estimates of undiscounted future net cash flows attributable to its oil and gas properties may change in the future. The primary factors that may affect

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estimates of future cash flows include future adjustments, both positive and negative, to proved and appropriate risk-adjusted probable and possible oil and gas reserves, results of future drilling activities, future prices for oil and natural gas, and increases or decreases in production and capital costs. As a result of these changes, there may be further impairments in the carrying values of these or other properties. Specifically, as part of the impairment review performed at December 31, 2015, the Company observed that a decline in excess of 30% in its future cash flow estimates for its Eagleville field in South Texas could result in an additional impairment being recorded in an amount that could be at least \$130.0 million.

Other property and equipment consists primarily of gas gathering systems, computer equipment, furniture and fixtures and an airplane which are depreciated over estimated useful lives ranging from three to 31½ years on a straight-line basis. In January 2015, the Company purchased a 20% interest in an airplane that previously had been owned 80% by the Company and 20% by two executive officers of the Company. The purchase price for the 20% interest of \$1.7 million was based on the then fair market value of the airplane determined by a third party. This related party transaction was approved by the Company's audit committee and board of directors.

Other Assets

Other assets primarily consist of deferred costs associated with the Company's bank credit facility. These costs are amortized over the life of the bank credit facility on a straight-line basis which approximates the amortization that would be calculated using an effective interest rate method.

Accrued Expenses

Accrued expenses at December 31, 2014 and 2015 consist of the following:

	As of December 31,	
	2014	2015
	(In thousands)	
Accrued drilling costs	\$26,269	\$5,306
Accrued interest payable	9,011	29,075
Accrued rig termination fees	2,600	—
Other	6,962	4,063
	\$44,842	\$38,444

Reserve for Future Abandonment Costs

The Company's asset retirement obligations relate to future plugging and abandonment costs of its oil and gas properties and related facilities disposal. The Company records a liability in the period in which an asset retirement obligation is incurred, in an amount equal to the estimated fair value of the obligation that is capitalized. Thereafter, this liability is accreted up to the final retirement cost. Accretion of the discount is included as part of depreciation, depletion and amortization in the accompanying consolidated statements of operations.

The following table summarizes the changes in the Company's total estimated liability:

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	2014	2015
	(In thousands)	
Reserve for Future Abandonment Costs at beginning of the year	\$14,534	\$14,900
New wells placed on production	1,480	310
Changes in estimates and timing	(1,796)	4,927
Liabilities settled and assets disposed of	(153)	(717)
Accretion expense	835	673
Reserve for Future Abandonment Costs at end of the year	\$14,900	\$20,093

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Stock-based Compensation

The Company has stock-based employee compensation plans under which stock awards, comprised of restricted stock and performance share units, are issued to employees and non-employee directors. The Company follows the fair value based method in accounting for equity-based compensation. Under the fair value based method, compensation cost is measured at the grant date based on the fair value of the award and is recognized on a straight-line basis over the award vesting period. Excess taxes on stock-based compensation are recognized as an adjustment to additional paid-in capital and as a part of cash flows from financing activities.

Segment Reporting

The Company presently operates in one business segment, the exploration and production of oil and natural gas.

Derivative Financial Instruments and Hedging Activities

The Company accounts for derivative financial instruments (including certain derivative instruments embedded in other contracts) as either an asset or liability measured at its fair value. Changes in the fair value of derivatives are recognized currently in earnings unless specific hedge accounting criteria are met. The Company estimates fair value based on a discounted cash flow model. The fair value of derivative contracts that expire in less than one year are recognized as current assets or liabilities. Those that expire in more than one year are recognized as long-term assets or liabilities. If the derivative is designated as a cash flow hedge, changes in fair value are recognized in other comprehensive income until the hedged item is recognized in earnings.

Major Purchasers

The Company has one major purchaser of its oil production that represented 36%, 35% and 25% of its total oil and gas sales in 2013, 2014 and 2015, respectively. The Company also has one major purchaser of its natural gas production that represented 51%, 53% and 52% of its total oil and gas sales in 2013, 2014 and 2015, respectively. The loss of any of these purchasers would not have a material adverse effect on the Company as there is an available market for its oil and natural gas production from other purchasers.

Revenue Recognition and Gas Balancing

Comstock utilizes the sales method of accounting for oil and natural gas revenues whereby revenues are recognized at the time of delivery based on the amount of oil or natural gas sold to purchasers. Revenue is typically recorded in the month of production based on an estimate of the Company's share of volumes produced and prices realized. The amount of oil or natural gas sold may differ from the amount to which the Company is entitled based on its revenue interests in the properties. The Company did not have any significant imbalance positions at December 31, 2014 or 2015. Sales of oil and natural gas generally occur at the wellhead. When sales of oil and gas occur at locations other than the wellhead, the Company accounts for costs incurred to transport the production to the delivery point as operating expenses.

General and Administrative Expenses

General and administrative expenses are reported net of reimbursements of overhead costs that are received from working interest owners of the oil and gas properties operated by the Company of \$11.9 million, \$13.2 million and \$13.9 million in 2013, 2014 and 2015, respectively.

Income Taxes

The Company accounts for income taxes using the asset and liability method, whereby deferred tax assets and liabilities are recognized for the future tax consequences attributable to differences between the financial statement carrying amounts of assets and liabilities and their respective tax basis, as well as the future tax consequences attributable to the future utilization of existing tax net operating loss and other types of carryforwards. Deferred tax assets and liabilities are measured using enacted tax rates expected to apply to taxable income in the years in which those temporary differences and carryforwards are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rates is recognized in income in the period that the change in rate is enacted.

Earnings Per Share

Basic earnings per share is determined without the effect of any outstanding potentially dilutive stock options and diluted earnings per share is determined with the effect of outstanding stock options that are potentially dilutive. Unvested share-based payment awards containing nonforfeitable rights to dividends are considered to be participatory securities and included in the computation of basic and diluted earnings per share pursuant to the two-class method. Performance share units ("PSUs") represent the right to receive a number of shares of the Company's common stock that may range from zero to up to three times the number of PSUs granted on the award date based on the achievement of certain performance measures during a performance period. The number of potentially dilutive shares related to PSUs is based on the number of shares, if any, which would be issuable at the end of the respective period, assuming that date was the end of the contingency period. The treasury stock method is used to measure the dilutive effect of PSUs.

Basic and diluted earnings per share for 2013, 2014 and 2015 were determined as follows:

	2013		2014		2015		
	Income (Loss)	Shares	Per Share Loss	Shares	Per Share Loss	Shares	Per Share
(In thousands except per share data)							
Net Loss From Continuing Operations	\$(106,723)		\$(57,111)		\$(1,047,109)		
Loss (Income) Allocable to Unvested Stock Grants	3,424		(595)		—		
Basic and Diluted Net Loss From Continuing Operations Attributable to Common Stock	\$(103,299)	46,553	\$(2.22)	46,547	\$(1.24)	46,113	\$(22.71)
Net Income From	\$147,752						

Discontinued
Operations
Income
Allocable to
Unvested Stock
Grants (4,742)
Basic and
Diluted Net
Income From
Discontinued
Operations
Attributable to
Common Stock \$143,010 46,553 \$ 3.07

Basic and diluted per share amounts are the same for each of the years ended December 31, 2013, 2014, and 2015 due to the net loss from continuing operations reported during each of those years.

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At December 31, 2013, 2014 and 2015, 1,515,889, 1,207,527 and 1,570,302 shares of unvested restricted stock, respectively, are included in common stock outstanding as such shares have a nonforfeitable right to participate in any dividends that might be declared and have the right to vote. Weighted average shares of unvested restricted stock included in common stock outstanding were as follows:

	2013	2014	2015
--	------	------	------

(In thousands)

Unvested restricted stock	1,544	1,190	1,466
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All stock options and PSUs were anti-dilutive to earnings and excluded from weighted average shares used in the computation of earnings per share due to the net loss from continuing operations in each period.

Options to purchase common stock and PSUs that were outstanding and that were excluded as anti-dilutive from determination of diluted earnings per share were as follows:

	2013	2014	2015
	(In thousands except per share data)		
Weighted average anti-dilutive stock options	130	115	101
Weighted average exercise price	\$ 32.90	\$ 32.90	\$ 32.95
Weighted average performance share units	75	323	217
Weighted average grant date fair value per unit	\$ 20.92	\$ 19.88	\$ 7.07

Supplementary Information With Respect to the Consolidated Statements of Cash Flows

For the purpose of the consolidated statements of cash flows, the Company considers all highly liquid investments purchased with an original maturity of three months or less to be cash equivalents.

Cash payments made for interest and income taxes for the years ended December 31, 2013, 2014 and 2015, respectively, were as follows:

	2013	2014	2015
	(In thousands)		
Cash Payments:			
Interest payments	\$83,560	\$62,812	\$94,177
Income tax payments	\$769	\$682	\$77

The Company capitalizes interest on its unevaluated oil and gas property costs during periods when it is conducting exploration activity on this acreage. The Company capitalized interest of \$4.7 million, \$10.2 million and \$0.9 million in 2013, 2014 and 2015, respectively, which reduced interest expense and increased the carrying value of its unevaluated oil and gas properties.

Discontinued West Texas Operations

In May 2013, the Company sold its oil and gas properties in the Delaware Basin located in Reeves County in West Texas which it acquired in December 2011 and certain other undeveloped leases in West Texas (the "West Texas Properties") to a third party. The Company received proceeds of \$823.1 million and realized a gain of \$230.0 million which is reflected as a component of income from discontinued operations in 2013. As a result of this divestiture, the consolidated financial statements and the related notes thereto present the results of the Company's West Texas Properties as discontinued operations. No general and administrative cost incurred by Comstock was allocated to discontinued operations during the periods presented. Unless indicated otherwise, the amounts presented in the accompanying notes to the consolidated financial statements relate to the Company's continuing operations.

Income from discontinued operations is comprised of the following:

	Year Ended December 31, 2013 (In thousands)
Revenues:	
Oil and gas sales	\$ 25,125
Costs and expenses:	
Production taxes	1,120
Gathering and transportation	501
Lease operating	9,853
Depletion, depreciation and amortization	8,649
Interest expense ⁽¹⁾	6,346
Total costs and expenses	26,469
Gain on sale	230,008
Income from discontinued operations before income taxes	228,664
Income tax expense:	
Current	(2,218)
Deferred	(78,694)
Total income tax expense	(80,912)
Net income from discontinued operations	\$ 147,752

(1) Interest expense was allocated to discontinued operations based on the ratio of the net assets of discontinued operations to our consolidated net assets plus long-term debt. Interest expense is net of capitalized interest of \$2,010 for the year ended December 31, 2013.

Recent accounting pronouncements

In May 2014, the Financial Accounting Standards Board ("FASB") issued Accounting Standards Update ("ASU") 2014-09, Revenue from Contracts with Customers (Topic 606) ("ASU 2014-09"), which supersedes nearly all existing revenue recognition guidance under existing generally accepted accounting principles. This new standard is based upon the principal that revenue is recognized to depict the transfer of goods or services to customers in an amount that reflects the consideration to which the entity expects to be entitled in exchange for those goods or services. ASU 2014-09 also requires additional disclosure about the nature, amount, timing and uncertainty of revenue and cash flows arising from customer contracts. ASU 2014-09 is effective for annual and interim periods beginning after December 15, 2017. Early adoption is permitted beginning with periods after December 15, 2016 and entities have the option of using either a full retrospective or modified approach to adopt ASU 2014-09. The Company is currently evaluating the new guidance and has not determined the impact this standard may have on its financial statements or decided upon the method of adoption.

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In August 2014, the FASB issued ASU No. 2014-15, Presentation of Financial Statements - Going Concern (Subtopic 205-40): Disclosure of Uncertainties about an Entity's Ability to Continue as a Going Concern ("ASU 2014-15"). ASU 2014-15 provides guidance about management's responsibility to evaluate whether there is substantial doubt about an entity's ability to continue as a going concern and sets rules for how this information should be disclosed in the financial statements. ASU 2014-15 is effective for annual periods ending after December 15, 2016 and interim periods thereafter. Early adoption is permitted. The Company does not expect adoption of ASU 2014-15 to have any impact on its consolidated financial condition, results of operations or cash flows.

In April 2015, the FASB issued ASU No. 2015-03, Interest-Imputation of Interest, Simplifying the Presentation of Debt Issuance Costs ("ASU 2015-03"). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability. ASU 2015-03 is effective for annual periods beginning after December 15, 2015 and interim periods thereafter. Early adoption is permitted. The Company has elected to early adopt ASU 2015-03 and accordingly \$9.8 million of debt issuance costs have been reclassified from long term assets to long term debt in our consolidated balance sheet as of December 31, 2014.

In November 2015, the FASB issued ASU No. 2015-17, Balance Sheet Classification of Deferred Taxes ("ASU 2015-17"). ASU 2015-17 requires that all deferred tax assets and liabilities be classified as non-current. ASU 2015-17 also discontinues allocation of valuation allowances between current and noncurrent tax assets. ASU 2015-17 is effective for annual periods beginning after December 15, 2016 and interim periods thereafter. Early adoption is permitted. The Company has elected to retrospectively early adopt ASU 2015-17. The effect of this change did not have a material impact on the Company's consolidated financial condition.

Subsequent Events

In January 2016, the Company completed an acreage swap with another operator which increased its Haynesville shale acreage by 3,637 net acres in DeSoto Parish, Louisiana including four producing wells (3.5 net). The Company exchanged 2,547 net acres in Atascosa County, Texas including seven producing wells (5.3 net) for the Haynesville shale properties. The swap was an equal value exchange that required no cash outlays.

In February 2016, the Company issued approximately 4.6 million shares of common stock in exchange for \$40.0 million in principal amount of the Company's 7¾% Senior Notes due 2019.

(2) Acquisitions and Dispositions of Oil and Gas Properties

During 2013, the Company acquired oil and gas leases in Burleson County, Texas for \$67.4 million. The Burleson County, Texas acquisition included one producing well and approximately 21,000 net acres which are prospective for oil in the Eagle Ford shale formation. During 2014, the Company commenced drilling operations on these properties and acquired additional interests in certain leases in Burleson County, Texas for approximately \$33.9 million. The

acquisition included approximately 9,000 net undeveloped acres and an additional 30% working interest in one producing well. Prior to the sale, during 2015, the Company acquired additional acreage, drilled an additional four wells and completed a total of 8 wells on this acreage at a cost of \$77.0 million. In 2015, the Company completed the sale of these properties for net proceeds of \$102.5 million and recognized a net loss on sale of \$112.1 million. Results of operations for these properties were as follows:

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	Year Ended	
	December 31,	
	2014	2015
	(In thousands)	
Total oil and gas sales	\$10,542	\$18,036
Total operating expenses ⁽¹⁾	(23,260)	(66,251)
Operating loss	\$(12,718)	\$(48,215)

(1) Includes direct operating expenses, depreciation, depletion and amortization and exploration expense. Excludes interest expense and general and administrative expenses.

During 2013, the Company acquired oil and gas leases in Mississippi and Louisiana for \$53.3 million. The Mississippi and Louisiana acquisition included approximately 51,000 net acres that are prospective for oil in the Tuscaloosa Marine shale formation.

In 2012, the Company entered into a participation agreement with Kohlberg Kravis Roberts & Co L.P. (together with its affiliates, "KKR") providing for the participation of KKR in Comstock's future development of certain of its Eagle Ford shale properties in South Texas. Under the terms of the participation agreement, KKR has the right to participate for one-third of Comstock's working interest in wells drilled on the Company's acreage comprising its Eagleville field in exchange for KKR paying \$25,000 per acre for the net acreage being acquired and one-third of the wells costs. Each well that KKR participates in is intended to earn KKR approximately one-third of the Company's working interest in approximately 80 acres. The Company received \$51.5 million and \$28.7 million for acreage and facility costs for new wells drilled subsequent to the closing in 2013 and 2014, respectively. There were no wells drilled under the joint venture in 2015.

In connection with acquisitions of producing oil and gas properties, the Company estimates the value of proved properties based on estimated future net cash flows and discounts them using a market-based rate that the Company determined appropriate at the acquisition date for the various proved reserve categories. Due to the unobservable nature of the inputs, the fair values of the proved oil and gas properties are considered Level 3 fair value measurements.

(3) Oil and Gas Producing Activities

Set forth below is certain information regarding the aggregate capitalized costs of oil and gas properties and costs incurred by the Company for its oil and gas property acquisition, development and exploration activities:

Capitalized Costs

	As of December 31,	
	2014	2015
	(In thousands)	
Unproved properties	\$201,459	\$84,144
Proved properties:		

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Leasehold costs	1,006,839	982,915
Wells and related equipment and facilities	3,275,249	3,349,307
Accumulated depreciation depletion and amortization	(2,298,450)	(3,389,786)
	\$2,185,097	\$1,026,580

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Costs Incurred

	For the Years Ended December 31,		
	2013	2014	2015
	(In thousands)		
Property Acquisitions:			
Unproved property acquisitions	\$ 130,113	\$ 91,960	\$ 12,972
Proved property acquisitions	6,471	2,400	—
Development costs	341,970	440,848	221,265
Exploration costs	439	52,080	12,265
	\$ 478,993	\$ 587,288	\$ 246,502

(4) Long-term Debt

Long-term debt is comprised of the following:

	As of December 31,	
	2014	2015
	(In thousands)	
Bank credit facility	\$ 375,000	\$ —
7 ³ / ₄ % senior notes due 2019:		
Principal	400,000	376,090
Premium, net of amortization	4,984	3,583
Debt issuance costs, net of amortization	(5,266)	(3,787)
9 ¹ / ₂ % senior notes due 2020:		
Principal	300,000	194,367
Discount, net of amortization	(9,539)	(5,040)
Debt issuance costs, net of amortization	(4,525)	(2,396)
10% senior secured notes due 2020:		
Principal	—	700,000
Debt issuance costs, net of amortization	—	(13,487)
	\$ 1,060,654	\$ 1,249,330

The premium and discount on the senior notes are being amortized over the life of the senior notes using the effective interest rate method. Issuance costs are amortized over the life of the senior notes on a straight-line basis which approximates the amortization that would be calculated using an effective interest rate method.

The following table summarizes Comstock's principal amount of debt as of December 31, 2015 by year of maturity:

	2016	2017	2018	2019	2020	Thereafter	Total
	(In thousands)						

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Bank credit facility	\$—	\$ —	\$ —	\$ —	\$ —	\$ —
7 ³ / ₄ % senior notes	—	—	—	376,090	—	— 376,090
9 ¹ / ₂ % senior notes	—	—	—	—	194,367	— 194,367
10% senior secured notes	—	—	—	—	700,000	— 700,000
	\$—	\$ —	\$ —	\$376,090	\$894,367	\$ — \$1,270,457

In March 2015, Comstock issued \$700.0 million of 10% senior secured notes (the "Secured Notes") which are due on March 15, 2020. Interest on the Secured Notes is payable semi-annually on each March 15 and September 15. Net proceeds from the issuance of the Secured Notes of \$683.8 million were used to retire the Company's bank credit facility and for general corporate purposes. Comstock also has

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outstanding (i) \$376.1 million of 7¾% senior notes (the "2019 Notes") which are due on April 1, 2019 and bear interest which is payable semi-annually on each April 1 and October 1 and (ii) \$194.4 million of 9½% senior notes (the "2020 Notes") which are due on June 15, 2020 and bear interest which is payable semi-annually on each June 15 and December 15. The Secured Notes are secured on a first priority basis equally and ratably with the Company's revolving credit facility described below, subject to payment priorities in favor of the revolving credit facility by the collateral securing the revolving credit facility, which consists of, among other things, at least 80% of the Company's and its subsidiaries' oil and gas properties. The Secured Notes, the 2019 Notes and 2020 Notes are general obligations of Comstock and are guaranteed by all of Comstock's subsidiaries. Such subsidiary guarantors are 100% owned and all of the guarantees are full and unconditional and joint and several obligations. There are no restrictions on the Company's ability to obtain funds from its subsidiaries through dividends or loans. As of December 31, 2015, the Company had no material assets or operations which are independent of its subsidiaries.

During 2015, Comstock purchased \$23.9 million in principal amount of the 2019 Notes and \$105.6 million in principal amount of the 2020 Notes for an aggregate purchase price of \$42.7 million. The gain of \$82.4 million recognized on the purchase of the 2019 Notes and 2020 Notes and the loss resulting from the write-off of deferred loan costs associated with Comstock's prior bank credit facility of \$3.7 million are included in the net gain on extinguishment of debt, which is reported as a component of other income (expense).

In connection with the issuance of the Secured Notes, Comstock entered into a \$50.0 million revolving credit facility with Bank of Montreal and Bank of America, N.A. The revolving credit facility is a four year commitment that matures on March 4, 2019. Indebtedness under the revolving credit facility is secured by substantially all of the Company's and its subsidiaries' assets and is guaranteed by all of its subsidiaries. Borrowings under the revolving credit facility bear interest at Comstock's option at either (1) LIBOR plus 2.5% or (2) the base rate (which is the higher of the administrative agent's prime rate, the federal funds rate plus 0.5% or 30 day LIBOR plus 1.0%) plus 1.5%. A commitment fee of 0.5% per annum is payable quarterly on the unused credit line. The revolving credit facility contains covenants that, among other things, restrict the payment of cash dividends and repurchases of common stock, limit the amount of consolidated debt that we may incur and limit the Company's ability to make certain loans, investments and divestitures. The only financial covenants are the maintenance of a current ratio of at least 1.0 to 1.0 and the maintenance of an asset coverage ratio of proved developed reserves to debt outstanding under the revolving credit facility of at least 2.5 to 1.0. The Company was in compliance with these covenants as of December 31, 2015.

(5) Commitments and Contingencies

Commitments

The Company rents office space and other facilities under noncancelable operating leases. Rent expense for the years ended December 31, 2013, 2014 and 2015 was \$1.4 million, \$1.5 million and \$1.5 million, respectively. Minimum future payments under the leases at December 31, 2015 are as follows:

	(In thousands)
2016	1,994
2017	2,021
2018	2,060
2019	1,560
2020	1,560
Thereafter	1,560
	\$ 10,755

As of December 31, 2015, the Company had commitments for contracted drilling rigs of \$1.6 million through May 2016.

The Company has entered into natural gas transportation and treating agreements through July 2019. Maximum commitments under these transportation agreements as of December 31, 2015 totaled \$6.4 million.

Contingencies

From time to time, the Company is involved in certain litigation that arises in the normal course of its operations. The Company records a loss contingency for these matters when it is probable that a liability has been incurred and the amount of the loss can be reasonably estimated. The Company does not believe the resolution of these matters will have a material effect on the Company's financial position, results of operations or cash flows and no material amounts are accrued relative to these matters at December 31, 2014 or 2015.

(6) Stockholders' Equity

The authorized capital stock of Comstock consists of 75 million shares of common stock, \$0.50 par value per share, and 5 million shares of preferred stock, \$10.00 par value per share. The preferred stock may be issued in one or more series, and the terms and rights of such stock will be determined by the Board of Directors. There were no shares of preferred stock outstanding at December 31, 2014 or 2015.

The Company paid dividends to its common stockholders of \$18.0 million and \$23.8 million in 2013 and 2014, respectively. During 2013, the Board of Directors also approved an open market share repurchase plan to repurchase up to \$100.0 million of its common stock on the open market. The Company made open market purchases of 1,000,000 shares and 631,096 shares with an aggregate cost of \$9.2 million and \$8.1 million in 2013 and 2014, respectively. The Company did not purchase any shares of its common stock in 2015.

On October 1, 2015, the Company entered into a net operating loss carryforwards ("NOLs") rights plan (the "Rights Plan") with American Stock Transfer & Trust Company, LLC, as rights agent. In connection with the adoption of the

Rights Plan, the board of directors of the Company declared a dividend of one preferred share purchase right ("Right") for each outstanding share of the Company's common stock. The dividend was payable on October 16, 2015 to stockholders of record as of the close

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of business on October 12, 2015. In addition, one Right automatically attached to each share of common stock issued between the record date and the date when the Rights become exercisable.

The Rights Plan was adopted in an effort to prevent potential significant limitations under Section 382 of the Internal Revenue Code of 1986, as amended (the "Code"), on Comstock's ability to utilize its current NOLs to reduce its future tax liabilities. If Comstock experiences an "ownership change," as defined in Section 382 of the Code, the Company's ability to fully utilize its NOLs on an annual basis will be substantially limited, and the timing of the usage of the NOLs could be substantially delayed, which could accordingly significantly impair the value of those benefits. The Rights Plan works by imposing a significant penalty upon any person or group that acquires 4.9% or more of the Company's outstanding common stock without the approval of the board of directors (an "Acquiring Person"). The Rights Plan also gives discretion to the Board to determine that someone is an Acquiring Person even if they do not own 4.9% or more of the outstanding common stock but do own 4.9% or more in value of the Company's outstanding stock, as determined pursuant to Section 382 of the Code and the regulations promulgated thereunder. Stockholders who currently own 4.9% or more of the Company's common stock will not trigger the Rights unless they acquire additional shares, subject to certain exceptions set forth in the Rights Plan. In addition, the Board has established procedures to consider requests to exempt certain acquisitions of the Company's securities from the Rights Plan if the board of directors determines that doing so would not limit or impair the availability of the NOLs or is otherwise in the best interests of the Company.

(7) Stock-based Compensation

The Company grants restricted shares of common stock and performance share units to key employees and directors as part of their compensation under the 2009 Long-term Incentive Plan. Future awards of stock options, restricted stock grants or other equity awards under the 2009 Long-term Incentive Plan are available with up to 957,845 shares of common stock.

During 2013, 2014 and 2015, the Company had \$12.8 million, \$10.7 million and \$8.1 million, respectively, in stock-based compensation expense which is included in general and administrative expenses. The excess income taxes associated with stock-based compensation recognized in additional paid in capital were \$2.0 million, \$1.1 million and \$2.0 million for the years ended December 31, 2013, 2014 and 2015, respectively.

Stock Options

At December 31, 2015, the Company had options outstanding to purchase 58,650 shares of common stock at \$33.22 per share. The stock options have a weighted average life of 1 year.

The following table summarizes information related to stock option activity under the Company's incentive plans for the year ended December 31, 2015:

	Number of Options	Weighted Average Exercise Price
Outstanding at January 1, 2015	115,150	\$32.90
Expired or forfeited	(56,500)	\$32.58

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Outstanding at December 31, 2015	58,650	\$33.22
Exercisable at December 31, 2015	58,650	\$33.22

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There were no stock option exercises in 2013, 2014 or 2015. No stock option has been granted since 2008 and all compensation cost related to stock options has been recognized. Stock options outstanding at December 31, 2014 and 2015 had no intrinsic value based on the closing price for the Company's common stock at those dates.

Restricted Stock

The fair value of restricted stock grants is amortized over the vesting period, generally one to four years, using the straight-line method. Total compensation expense recognized for restricted stock grants was \$9.8 million, \$7.3 million and \$6.0 million for the years ended December 31, 2013, 2014 and 2015, respectively. The fair value of each restricted share on the date of grant is equal to the fair market price of a share of the Company's stock.

A summary of restricted stock activity for the year ended December 31, 2015 is presented below:

	Number of Restricted Shares	Weighted Average Grant Price
Outstanding at January 1, 2015	1,207,527	\$19.91
Granted	1,010,371	\$5.34
Vested	(576,743)	\$22.23
Forfeitures	(70,853)	\$14.85
Outstanding at December 31, 2015	1,570,302	\$9.91

The per share weighted average fair value of restricted stock grants in 2013, 2014 and 2015 was \$16.44, \$20.24 and \$5.34, respectively. Total unrecognized compensation cost related to unvested restricted stock of \$5.1 million as of December 31, 2015 is expected to be recognized over a period of 1.8 years. The fair value of restricted stock which vested in 2013, 2014 and 2015 was \$7.0 million, \$10.0 million and \$3.7 million, respectively.

Performance Share Units

The Company issues PSUs as part of its long-term equity incentive compensation. PSU awards can result in the issuance of common stock to the holder if certain performance criteria is met during a performance period. The performance periods consist of one year, two years and three years, respectively. The performance criteria for the PSUs are based on the Company's annualized total stockholder return ("TSR") for the performance period as compared with the TSR of certain peer companies for the performance period. The costs associated with PSUs are recognized as general and administrative expense over the performance periods of the awards.

The fair value of PSUs was measured at the grant date using a stochastic process method utilizing the Geometric Brownian Motion Model ("GBM Model"). A stochastic process is a mathematically defined equation that can create a series of outcomes over time. These outcomes are not deterministic in nature, which means that by iterating the equations multiple times, different results will be obtained for those iterations. In the case of the Company's PSUs, the Company cannot predict with certainty the path its stock price or the stock prices of its peers will take over the future performance periods. By using a stochastic simulation, the Company can create multiple prospective total return pathways, statistically analyze these simulations, and ultimately make inferences to the most likely path the total return will take. As such, because future stock returns are stochastic, or probabilistic with some direction in nature, the stochastic method, specifically the GBM Model, is deemed an appropriate method by which to determine the fair value of the PSUs. Significant assumptions used in this simulation include the Company's expected volatility and a risk-free interest rate based on U.S. Treasury yield curve rates with maturities consistent with the vesting periods, as

well as the volatilities for each of the Company's peers.

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Assumptions regarding volatility included the historical volatility of each company's stock and the implied volatilities of publicly traded stock options. For the PSUs granted in 2014, the valuation inputs included a risk free interest rate of 0.6% and a range of volatilities of 38% to 70%. For the PSUs granted in 2015, the valuation inputs included a risk free rate of 1.1% and a range of volatilities of 37% to 65%.

In 2014, the Company granted 188,958 PSUs with a grant date fair value of \$3.7 million, or \$19.81 per unit. In 2015, the Company granted 471,249 PSUs with a grant date fair value of \$0.7 million, or \$1.46 per unit. No PSUs were awarded in 2013. The fair value of PSUs is amortized over the vesting period of one to three years, using the straight-line method. Total compensation expense recognized for PSUs was \$3.0 million, \$3.4 million and \$2.1 million for the years ended December 31, 2013, 2014 and 2015, respectively.

A summary of PSU activity for the year ended December 31, 2015 is presented below:

	Number of PSUs	Weighted Average Grant Price
Outstanding at January 1, 2015	373,072	\$19.88
Granted	471,249	\$1.46
Unearned or forfeited	(174,717)	\$19.27
Outstanding at December 31, 2015	669,604	\$7.07

The number of awards assumes a one multiplier. The final number of shares of common stock issued may vary depending upon the performance multiplier, and can result in the issuance of zero to 1,400,173 shares of common stock based on the achieved performance ranges from zero to two. As of December 31, 2015, there was \$2.0 million of total unrecognized expense related to PSUs, which is being amortized through December 31, 2017.

(8) Retirement Plan

The Company has a 401(k) profit sharing plan which covers all of its employees. At its discretion, Comstock may match the employees' contributions to the plan. Matching contributions to the plan were \$702,000, \$834,000 and \$888,000 for the years ended December 31, 2013, 2014 and 2015, respectively.

(9) Income Taxes

The following is an analysis of the consolidated income tax benefit from continuing operations:

2013	2014	2015
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(In thousands)

Current	\$134	\$(12)	\$804
Deferred	(56,291)	(24,677)	(155,249)
	\$(56,157)	\$(24,689)	\$(154,445)

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Deferred income taxes are provided to reflect the future tax consequences or benefits of differences between the tax basis of assets and liabilities and their reported amounts in the financial statements using enacted tax rates. The difference between the Company's effective tax rate and the 35% federal statutory rate is caused by non-deductible stock compensation, state taxes and the establishment of a valuation allowance on deferred taxes. The impact of these items varies based upon the Company's full year loss and the jurisdictions that are expected to generate the projected losses.

In recording deferred income tax assets, the Company considers whether it is more likely than not that some portion or all of its deferred income tax assets will be realized in the future. The ultimate realization of deferred income tax assets is dependent upon the generation of future taxable income during the periods in which those deferred income tax assets would be deductible. The Company believes that after considering all the available objective evidence, historical and prospective, with greater weight given to historical evidence, management is not able to determine that it is more likely than not that all of its deferred tax assets will be realized. As a result, in 2015 the Company established an additional valuation allowance of \$775.3 million, with a tax effect of \$271.4 million for its estimated U.S. federal net operating loss carryforwards and other U.S. federal tax assets and an additional valuation allowance of \$215.5 million, with a tax effect of \$11.2 million, for its estimated Louisiana state net operating loss carryforwards that are not expected to be utilized due to uncertainty of generating taxable income prior to the expiration of the respective U.S. federal and Louisiana state carry-over periods.

The difference between the Company's customary rate of 35% and the effective tax rate on income from continuing operations is due to the following:

	2013	2014	2015
	(In thousands)		
Tax benefit at statutory rate	\$(57,008)	\$(28,630)	\$(420,544)
Tax effect of:			
Nondeductible compensation	1,545	756	539
State taxes, net of federal tax benefit	(10,902)	(5,108)	(17,502)
Valuation allowance on deferred tax assets	10,103	8,086	282,869
Other	105	207	193
Total	\$(56,157)	\$(24,689)	\$(154,445)
	2013	2014	2015
Statutory rate	35.0%	35.0%	35.0%
Tax effect of:			
Nondeductible compensation	(0.9)	(0.9)	—
State taxes, net of federal tax benefit	6.7	6.2	1.4
Valuation allowance on deferred tax assets	(6.2)	(9.9)	(23.5)
Other	(0.1)	(0.2)	—
Effective tax rate	34.5%	30.2%	12.9%

The tax effects of significant temporary differences representing the net deferred tax liability at December 31, 2014 and 2015 were as follows:

	2014	2015
	(In thousands)	
Deferred tax assets:		
Property and equipment	\$—	\$49,116
Net operating loss carryforwards	126,026	255,231
Alternative minimum tax carryforward	20,435	20,435
Other	7,854	8,201
	154,315	332,983
Valuation allowance on deferred tax assets	(46,639)	(329,508)
Deferred tax assets	107,676	3,475
Deferred tax liabilities:		
Property and equipment	(259,222)	—
Unrealized hedging income	—	(506)
Other	(3,001)	(4,934)
Deferred tax liabilities	(262,223)	(5,440)
Net deferred tax liability	\$(154,547)	\$(1,965)

At December 31, 2015, Comstock had the following carryforwards available to reduce future income taxes:

Types of Carryforward	Years of Expiration	Carryforward Amount
Net operating loss - U.S. federal	2017 – 2035	\$ 558,718
Net operating loss - Louisiana	2020 – 2035	\$ 1,147,689
Alternative minimum tax credits	Unlimited	\$ 20,435

As of December 31, 2015, The Company had \$558.7 million in U.S. federal net operating loss carryforwards. The utilization of \$34.7 million of the U.S. federal net operating loss carryforward is limited to approximately \$1.1 million per year pursuant to a prior change of control of an acquired company. Accordingly, as of December 31, 2014, a valuation allowance of \$23.0 million, with a tax effect of \$8.0 million, has been established for the estimated U.S. federal net operating loss carryforwards that will not be utilized as a result of the change in control. As of December 31, 2015, the Company had also established a valuation allowance of \$775.3 million, with a tax effect of \$271.4 million, against its other U.S. federal net operating loss carryforwards that are not subject to a change in control and other U.S. federal tax assets due to the uncertainty of generating future taxable income prior to the expiration of the carry-over period. In addition, as of December 31, 2015, the Company established a valuation allowance of \$957.7 million, with a tax effect of \$49.8 million, against its Louisiana state net deferred tax assets due to the uncertainty of generating taxable income in the state of Louisiana prior to the expiration of the carry-over period. As of December 31, 2014, the Company had a valuation allowance of \$742.2 million, with a tax effect of \$38.6 million, against its

Louisiana state deferred tax assets.

Future use of the Company's federal and state net operating loss carryforwards may be limited in the event that a cumulative change in the ownership of Comstock's common stock by more than 50% occurs within a three-year period. Such a change in ownership could result in a substantial portion of Comstock's net operating loss carryforwards being eliminated or becoming restricted, and the Company may need to recognize an additional valuation allowance reflecting the restricted use of the net operating

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loss carryforwards in the period when such an ownership change occurred. The Company established a rights plan on October 1, 2015 to deter ownership changes that would trigger this limitation.

The Company's federal income tax returns for the years subsequent to December 31, 2011 remain subject to examination. The Company's income tax returns in major state income tax jurisdictions remain subject to examination for the year ended December 31, 2008 and various periods subsequent to December 31, 2010. State tax returns in one state jurisdiction are currently under review. The Company currently believes that resolution of these matters will not have a material impact on its financial statements. The Company currently believes that its significant filing positions are highly certain and that all of its other significant income tax filing positions and deductions would be sustained upon audit or the final resolution would not have a material effect on the consolidated financial statements. Therefore, the Company has not established any significant reserves for uncertain tax positions. Interest and penalties resulting from audits by tax authorities have been immaterial and are included in the provision for income taxes in the consolidated statements of operations.

(10) Derivative Financial Instruments and Hedging Activities

Comstock periodically uses swaps, floors and collars to hedge oil and natural gas prices and interest rates. Swaps are settled monthly based on differences between the prices specified in the instruments and the settlement prices of futures contracts. Generally, when the applicable settlement price is less than the price specified in the contract, Comstock receives a settlement from the counterparty based on the difference multiplied by the volume or amounts hedged. Similarly, when the applicable settlement price exceeds the price specified in the contract, Comstock pays the counterparty based on the difference. Comstock generally receives a settlement from the counterparty for floors when the applicable settlement price is less than the price specified in the contract, which is based on the difference multiplied by the volumes hedged. For collars, generally Comstock receives a settlement from the counterparty when the settlement price is below the floor and pays a settlement to the counterparty when the settlement price exceeds the cap. No settlement occurs when the settlement price falls between the floor and cap.

All of the Company's derivative financial instruments are used for risk management purposes and by policy none are held for trading or speculative purposes. Comstock minimizes credit risk to counterparties of its derivative financial instruments through formal credit policies, monitoring procedures, and diversification. All of Comstock's derivative financial instruments are with parties that are lenders under its bank credit facility. The Company is not required to provide any credit support to its counterparties other than cross collateralization with the assets securing its bank credit facility. None of the Company's derivative financial instruments involve payment or receipt of premiums.

During 2013 and 2014, the Company hedged 2,160,000 barrels and 2,438,000 barrels, respectively, of its oil production at an average NYMEX West Texas Intermediate oil price of \$98.67 per barrel and \$96.56 per barrel, respectively. During 2015, the Company hedged 1,800,000 Mmbtu of its gas production at an average NYMEX Henry Hub natural gas price of \$3.20 per Mmbtu.

As of December 31, 2015, the Company had the following outstanding commodity derivatives:

Commodity and Derivative Type	Weighted-Average Contract Price	Contract Volume (Mmbtu)	Contract Period
Natural Gas Swap Agreements	\$3.20 per Mmbtu	1,800,000	Jan. 2016 – June 2016

None of the derivative contracts were designated as cash flow hedges. The Company recognizes cash settlements and changes in the fair value of its derivative financial instruments as a single component of other income (expenses).

The gain (loss) on derivative financial instruments was a loss of \$8.4 million, a gain of \$8.2 million and a gain of \$2.7 million for the years ended December 31, 2013, 2014 and 2015, respectively. Cash settlements received on derivative financial instruments were \$2.3 million, \$9.1 million and \$1.2 million for the years ended December 31, 2013, 2014 and 2015, respectively. The estimated fair value of the Company's derivative financial instruments, which equaled their carrying value, was an asset of \$1.4 million as of December 31, 2015 which was reflected as a current asset based on estimated settlement dates.

(11) Supplementary Quarterly Financial Data (Unaudited)

	2014				
	First	Second	Third	Fourth	Total
	(In thousands, except per share data)				
Total oil and gas sales	\$ 141,909	\$ 155,723	\$ 144,983	\$ 112,616	\$ 555,231
Operating income (loss)	\$ 20,228	\$ 27,729	\$ 263	\$(80,291)	\$(32,071)
Net income (loss)	\$ 1,165	\$ 1,898	\$(1,903)	\$(58,271)	\$(57,111)
Income (loss) per share:					
Basic and diluted	\$0.02	\$0.04	\$(0.04)	\$(1.26)	\$(1.24)

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	First	Second	Third	Fourth	Total
	(In thousands, except per share data)				
Total oil and gas sales	\$66,522	\$77,312	\$61,360	\$47,228	\$252,422
Operating loss	\$(96,928)	\$(182,185)	\$(596,026)	\$(290,515)	\$(1,165,654)
Net income (loss)	\$(78,502)	\$(135,068)	\$(544,996)	\$(288,543)	\$(1,047,109)
Income (loss) per share:					
Basic and diluted	\$(1.71)	\$(2.93)	\$(11.81)	\$(6.25)	\$(22.71)

Basic and diluted per share amounts are the same for each of the quarters and for the years ended where a net loss was reported.

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Results of operations include the following non-routine items of income (expense), which are presented before the effect of income taxes:

	2014				
	First	Second	Third	Fourth	Total
	(In thousands)				
Impairments of unproved oil and gas properties	\$—	\$—	\$—	\$(487)	\$(487)
Impairments of proved oil and gas properties	\$—	\$(256)	\$(15)	\$(59,997)	\$(60,268)

	2015				
	First	Second	Third	Fourth	Total
	(In thousands)				
Gain (loss) on sale of oil and gas properties	\$—	\$(111,830)	\$52	\$(307)	\$(112,085)
Net gain (loss) on extinguishment of debt	\$(2,735)	\$7,267	\$51,054	\$23,155	\$78,741
Impairments of unproved oil and gas properties	\$(40,432)	\$(23,040)	\$(5,090)	\$(385)	\$(68,947)
Impairments of proved oil and gas properties	\$(403)	\$(1,984)	\$(544,714)	\$(254,246)	\$(801,347)

(12) Oil and Gas Reserves Information (Unaudited)

Set forth below is a summary of the changes in Comstock's net quantities of oil and natural gas reserves for its continuing operations for each of the three years in the period ended December 31, 2015:

	2013		2014		2015	
	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)	Oil (MBbls)	Natural Gas (MMcf)
Proved Reserves:						
Beginning of year	18,899	437,445	21,976	452,653	20,854	495,266
Revisions of previous estimates	28	23,321	(2,182)	3,998	(5,096)	(41,437)
Extensions and discoveries	5,363	47,581	5,373	78,383	231	168,539
Sales of minerals in place	—	—	—	—	(3,671)	(5,096)

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Production	(2,314)	(55,694)	(4,313)	(39,768)	(3,089)	(47,676)
End of year	21,976	452,653	20,854	495,266	9,229	569,596
Proved Developed Reserves:						
Beginning of year	8,389	362,426	13,914	344,278	16,247	324,598
End of year	13,914	344,278	16,247	324,598	9,229	311,130

The downward revisions in 2015 were primarily related to the decline in oil and natural gas prices. In 2015 price-related revisions were downward revisions of 4,958 MBbls of oil and 77,659 MMcf of natural gas.

The proved oil and gas reserves utilized in the preparation of the financial statements were estimated by Lee Keeling and Associates, independent petroleum consultants, in accordance with guidelines established by the Securities and Exchange Commission and the Financial Accounting Standards Board, which require that reserve reports be prepared under existing economic and operating conditions with no provision for price and cost escalation except by contractual agreement. All of the Company's reserves are located onshore in the continental United States of America.

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The following table sets forth the standardized measure of discounted future net cash flows relating to proved reserves at December 31, 2014 and 2015:

	2014	2015
	(In thousands)	
Cash Flows Relating to Proved Reserves:		
Future Cash Flows	\$3,891,953	\$1,763,146
Future Costs:		
Production	(1,260,580)	(705,146)
Development and Abandonment	(571,200)	(362,874)
Future Income Taxes	(192,600)	(1,231)
Future Net Cash Flows	1,867,573	693,895
10% Discount Factor	(776,913)	(321,756)
Standardized Measure of Discounted Future Net Cash Flows	\$1,090,660	\$372,139

The standardized measure of discounted future net cash flows at the end of 2014 and 2015 was determined based on the simple average of the first of month market prices for oil and natural gas for each year. Prices were \$92.55 per barrel of oil and \$3.96 per Mcf of natural gas for 2014 and \$46.88 per barrel of oil and \$2.34 per Mcf of natural gas for 2015. Prices used in determining quantities of oil and natural gas reserves and future cash inflows from oil and natural gas reserves represent prices received at the Company's sales point. These prices have been adjusted from posted or index prices for both location and quality differences. Future development and production costs are computed by estimating the expenditures to be incurred in developing and producing proved oil and gas reserves at the end of the year, based on year end costs and assuming continuation of existing economic conditions. Future income tax expenses are computed by applying the appropriate statutory tax rates to the future pre-tax net cash flows relating to proved reserves, net of the tax basis of the properties involved. The future income tax expenses give effect to permanent differences and tax credits, but do not reflect the impact of future operations.

The following table sets forth the changes in the standardized measure of discounted future net cash flows relating to proved reserves for the years ended December 31, 2013, 2014 and 2015:

	2013	2014	2015
	(In thousands)		
Standardized Measure, Beginning of Year	\$641,325	\$807,217	\$1,090,660
Net change in sales price, net of production costs	43,117	5,911	(751,774)
Development costs incurred during the year which were previously estimated	187,643	344,590	157,390
Revisions of quantity estimates	48,411	(40,993)	(111,454)
Accretion of discount	81,434	105,400	114,427
Changes in future development and abandonment costs	(157,207)	(10,909)	14,901
Changes in timing and other	80,348	(19,028)	(44,439)
Extensions and discoveries	291,582	163,559	56,216
Sales of minerals in place	—	—	(43,694)
Sales, net of production costs	(335,677)	(458,254)	(163,336)
Net changes in income taxes	(73,759)	193,167	53,242
Standardized Measure, End of Year	\$807,217	\$1,090,660	\$372,139

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