CONCHO RESOURCES INC
Form 10-K
February 26, 2015

UNITED STATES SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934
For the fiscal year ended December 31, 2014

or

o **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from ____________________ to ____________________

Commission file number: 1-33615

Concho Resources Inc.

(Exact name of registrant as specified in its charter)

Delaware State or other jurisdiction of incorporation or organization	**76-0818600** (I.R.S. Employer Identification No.)
One Concho Center **600 West Illinois Avenue** **Midland, Texas** (Address of principal executive offices)	**79701** (Zip code)

(432) 683-7443
Registrant's telephone number, including
area code

Securities Registered Pursuant to
Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
Common Stock, $0.001 par value	**New York Stock Exchange**

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 o

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 o 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 o

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate website, 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 o

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§229.405 of this chapter) 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 definition of "large accelerated filer," "accelerated filer" and "smaller reporting company" in Rule 12b-2 of the Exchange Act.

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Act). Yes o No

Aggregate market value of the voting and non-voting common equity held by non-affiliates computed by reference to the price at which the common equity was last sold, or the average bid and asked price of such common equity, as of the last business day of the registrant's most recently completed second fiscal quarter:	$16,062,966,367
Number of shares of registrant's common stock outstanding as of February 24, 2015:	113,101,342

Documents Incorporated by Reference:

Portions of the registrant's definitive proxy statement for its 2015 Annual Meeting of Stockholders, which will be filed with the United States Securities and Exchange Commission within 120 days of December 31, 2014, are incorporated by reference into Part III of this Form 10-K for the year ended December 31, 2014.

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CAUTIONARY STATEMENT REGARDING FORWARD-LOOKING STATEMENTS

Various statements and information contained in or incorporated by reference into this report that express a belief, expectation, or intention, or that are not statements of historical fact, are forward-looking statements within the meaning of Section 27A of the Securities Act of 1933 (the "Securities Act") and Section 21E of the Securities Exchange Act of 1934 (the "Exchange Act"). These forward-looking statements include statements, projections and estimates concerning our operations, performance, business strategy, oil and natural gas reserves, drilling program, capital expenditures, liquidity and capital resources, the timing and success of specific projects, outcomes and effects of litigation, claims and disputes, derivative activities and potential financing. Forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "plan," "goal" or other words that convey the uncertainty of future events or outcomes. Forward-looking statements are not guarantees of performance. We have based these forward-looking statements on our current expectations and assumptions about future events and their potential effect on us. These statements are based on certain assumptions and analyses made by us in light of our experience and our perception of historical trends, current conditions and expected future developments as well as other factors we believe are appropriate under the circumstances. Actual results may differ materially from those implied or expressed by any forward-looking statements. These forward-looking statements speak only as of the date of this report, or if earlier, as of the date they were made. We disclaim any obligation to update or revise these statements unless required by law, and we caution you not to rely on them unduly. While our management considers these expectations and assumptions to be reasonable, they are inherently subject to significant business, economic, competitive, regulatory and other risks, contingencies and uncertainties relating to, among other matters, the risks discussed "Item 1A. Risk Factors," as well as those factors summarized below:

- declines in the prices we receive for our oil and natural gas;
- uncertainties about the estimated quantities of oil and natural gas reserves;
- drilling and operating risks, including risks related to properties where we do not serve as the operator and risks related to hydraulic fracturing activities;
- the adequacy of our capital resources and liquidity including, but not limited to, access to additional borrowing capacity under our credit facility;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing and the export of oil and natural gas;
- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;
- difficult and adverse conditions in the domestic and global capital and credit markets;
- risks related to the concentration of our operations in the Permian Basin of Southeast New Mexico and West Texas;
- disruptions to, capacity constraints in or other limitations on the pipeline systems that deliver our oil, natural gas liquids and natural gas and other processing and transportation considerations;
- shortages of oilfield equipment, supplies, water, services and qualified personnel and increased costs for such equipment, supplies, services and personnel;

- potential financial losses or earnings reductions from our commodity price management program;
- risks and liabilities associated with acquired properties or businesses;
- uncertainties about our ability to successfully execute our business and financial plans and strategies;
- uncertainties about our ability to replace reserves and economically develop our current reserves;
- general economic and business conditions, either internationally or domestically;
- competition in the oil and natural gas industry; and
- uncertainty concerning our assumed or possible future results of operations.

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

PART I

Item 1. Business

General

Concho Resources Inc., a Delaware corporation (“Concho,” the “Company,” “we,” “us” and “our”) formed in February 2006, i an independent oil and natural gas company engaged in the acquisition, development and exploration of oil and natural gas properties. Our core operating areas are located in the Permian Basin region of Southeast New Mexico and West Texas, a large onshore oil and natural gas basin in the United States. The Permian Basin is one of the most prolific oil and natural gas producing regions in the United States and is characterized by an extensive production history, long reserve life, multiple producing horizons and enhanced recovery potential. More recently, the Permian Basin has experienced a resurgence in primary drilling activity related to horizontal “unconventional” targets, primarily in the Delaware and Midland Basins. We refer to our three core operating areas as the (i) New Mexico Shelf, where we primarily target the Yeso formation with horizontal and vertical development, (ii) Delaware Basin, where we use horizontal drilling and technology to target the Bone Spring formation (including the Avalon shale and the Bone Spring sands) and the Wolfcamp shale formation and (iii) Texas Permian in the Midland Basin, where we target the Wolfcamp and Spraberry formations with horizontal and vertical development. We intend to grow our reserves and production through development drilling and exploration activities on our multi-year project inventory and through acquisitions that meet our strategic and financial objectives.

Business and Properties

Our core operations are focused in the Permian Basin, which underlies an area of Southeast New Mexico and West Texas approximately 250 miles wide and 300 miles long. Commercial accumulations of hydrocarbons occur in multiple stratigraphic horizons, at depths ranging from approximately 1,000 feet to over 25,000 feet. At December 31, 2014, substantially all of our 637.2 MMBoe total estimated proved reserves were located in our core operating areas and consisted of approximately 58.1 percent oil and 41.9 percent natural gas. We have assembled a multi-year inventory of vertical and horizontal development drilling and exploration projects, including projects to further evaluate the regional extent and multi-pay potential of our New Mexico Shelf, Delaware Basin and Texas Permian assets. We believe these projects, combined with the application of horizontal drilling and enhanced completion technology, will enable us to further grow our proved reserves and production.

The following table sets forth information with respect to drilling of wells commenced during the periods indicated:

	Years Ended December 31, 2014	2013	2012
Gross wells	595	633	840
Net wells	370	371	519
Percent of gross wells drilled horizontally	69.1%	43.8%	26.8%
Percent of gross wells:			
Producers	69.9%	83.1%	80.0%
Unsuccessful	0.2%	0.3%	1.0%
Awaiting completion at year-end	29.9%	16.6%	19.0%
	100.0%	100.0%	100.0%

In 2014, we drilled 69.1 percent of our wells horizontally. We will continue to evaluate converting our identified vertical locations to horizontal opportunities, where possible. We believe horizontal drilling is more capital efficient than vertical drilling in many situations. In 2015, we plan to spend approximately 90 percent of our capital budget for drilling and completion activities on horizontal drilling opportunities.

We produced approximately 40.9 MMBoe, 33.6 MMBoe and 29.8 MMBoe of oil and natural gas during 2014, 2013 and 2012, respectively. Included in 2012 production amounts are 1,807 MBoe of production related to our discontinued operations. In addition, we increased our average daily production from 97.0 MBoe during the fourth quarter of 2013 to 124.8 MBoe during the fourth quarter of 2014. During 2014, approximately 56 percent of our total production was attributable to horizontal wells. During 2014, we increased our total estimated proved reserves by approximately 134.3 MMBoe, including acquisitions of 5.7 MMBoe.

Summary of Core Operating Areas and Other Plays

The following is a summary of information regarding our core operating areas and other plays:

	December 31, 2014						Year Ended December 31, 2014 Average
Areas	**Estimated Proved Reserves (MBoe)**	**PV-10 ($ in millions)**	**% Oil**	**% Proved Developed**	**Total Gross Acreage**	**Total Net Acreage**	**Daily Production (Boe per Day)**
Core Operating Areas:							
New Mexico Shelf	247,816	$ 4,315.2	56.8%	65.7%	157,826	106,559	31,572
Delaware Basin	243,848	4,878.8	57.3%	53.0%	636,242	423,885	56,641
Texas Permian	145,413	2,189.6	61.8%	58.3%	329,007	163,014	23,738
Other	106	1.2	6.0%	100.0%	4,116	2,893	36
Total	637,183	$ 11,384.8(a)	58.1%	59.1%	1,127,191	696,351	111,987

(a) Our Standardized Measure at December 31, 2014 was $8.0 billion. The present value of estimated future net revenues discounted at an annual rate of 10 percent ("PV-10") is not a GAAP financial measure and is derived from the Standardized Measure, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves. See "Item 1. Business —Non-GAAP Financial Measures and Reconciliations."

Core operating areas

New Mexico Shelf. At December 31, 2014, we had estimated proved reserves in this area of 247.8 MMBoe, representing 38.9 percent of our total proved reserves and 37.9 percent of our PV-10.

Within this area our primary objectives are the Yeso, San Andres and Grayburg formations, with producing depths ranging from approximately 900 feet to 7,500 feet. We have drilled and plan to continue to evaluate drilling horizontally in the Yeso formation. During 2014, we continued our vertical development of the Yeso formation on 10 and 20 acre spacing.

During the year ended December 31, 2014, we commenced drilling or participated in the drilling of 134 (85 net) wells in this area. Throughout 2014, we completed 121 (74 net) wells that are producing. Additionally in 2014, we abandoned 3 (2 net) wells that were deemed unsuccessful. During 2014, approximately 46 percent of the wells we commenced or participated in drilling were drilled horizontally.

In 2015, we plan to spend approximately $200 million, or 11 percent, of our 2015 drilling and completions capital budget on the New Mexico Shelf assets. We expect that approximately 52 percent of these wells will be drilled horizontally.

Delaware Basin. At December 31, 2014, we had estimated proved reserves in the Delaware Basin of 243.8 MMBoe, representing 38.3 percent of our total proved reserves and 42.8 percent of our PV-10.

Within this area, we utilize horizontal drilling and completion technologies to target (i) the oil-prone Bone Spring formation that includes (a) three Bone Spring sandstone members and (b) the Avalon shale and (ii) the Wolfcamp shale. These formations produce from 4,700 feet to 13,500 feet for our currently targeted activity. Within the Delaware Basin, we have drilled and are also actively evaluating the Delaware sands and Penn shale opportunities on our acreage.

During the year ended December 31, 2014, we commenced drilling or participated in the drilling of 294 (199 net) wells in this area. Throughout 2014, we completed 247 (173 net) wells that are producing. Additionally in 2014, we abandoned 8 (8 net) wells that were deemed unsuccessful. During 2014, we continued (i) development and step-out activity targeting the Brushy Canyon sands, Avalon shale, Bone Spring sands and Wolfcamp shale and (ii) evaluation of our enhanced stimulation procedures of certain horizontal wells. During 2014, approximately all of the wells we commenced or participated in drilling were drilled horizontally.

In 2015, we plan to spend approximately $1.3 billion, or 72 percent, of our 2015 drilling and completions capital budget on our Delaware Basin assets. We expect that 100 percent of these wells will be drilled horizontally.

Texas Permian. At December 31, 2014, our estimated proved reserves of 145.4 MMBoe in this area accounted for 22.8 percent of our total proved reserves and 19.3 percent of our PV-10 value.

Our primary objectives in the Texas Permian area are the vertical Wolfberry and the horizontal zones in the same interval in the Midland Basin. “Wolfberry” is the term applied to the combined production from the Spraberry and Wolfcamp horizons out of vertical wellbores, which are typically encountered at depths of 7,500 feet to 10,500 feet. These formations are comprised of a sequence of basinal, interbedded sands, shales and carbonates. On our Texas Permian assets we are continuing to evaluate (i) horizontal Wolfcamp and Spraberry drilling, (ii) other potential zones on our acreage and (iii) ultimate well spacing.

During the year ended December 31, 2014, we commenced drilling or participated in the drilling of 167 (86 net) wells in this area. Throughout 2014, we completed 145 (71 net) wells that are producing. Additionally in 2014, we abandoned 1 (1 net) well that was deemed unsuccessful. During 2014, approximately 34 percent of the wells we commenced or participated in drilling were drilled horizontally.

In 2015, we plan to spend approximately $300 million, or 17 percent, of our 2015 drilling and completions capital budget on the Texas Permian assets. We expect that approximately 39 percent of these wells will be drilled horizontally.

Drilling Activities

The following table sets forth information with respect to (i) wells drilled and completed during the periods indicated and (ii) wells drilled in a prior period but completed in the periods indicated. The information should not be considered indicative of future performance, nor should a correlation be assumed between the number of productive wells drilled, quantities of reserves found or economic value.

	Years Ended December 31,					
	2014		2013		2012	
	Gross	Net	Gross	Net	Gross	Net
Development wells:						
Productive	201	128	354	204	468	318
Dry	1	1	-	-	1	1
Exploratory wells:						
Productive	312	190	321	184	331	191
Dry	11	10	4	4	4	3
Total wells:						
Productive	513	318	675	388	799	509
Dry (a)	12	11	4	4	5	4
Total	525	329	679	392	804	513

(a) The dry category includes 5 (3.8 net) wells that were unsuccessful due to mechanical or other issues for the year ended December 31, 2014.

The following table sets forth information about wells for which drilling was in-progress or are pending completion at December 31, 2014, which are not included in the above table:

	Drilling In-Progress		Pending Completion	
	Gross	Net	Gross	Net
Development wells	14	8	57	34
Exploratory wells	31	21	82	45
Total	45	29	139	79

Our Production, Prices and Expenses

The following table sets forth summary information concerning our production and operating data from continuing operations for the years ended December 31, 2014, 2013 and 2012. The table below excludes production and operating data that we have classified as discontinued operations, which is more fully described in Note 13 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data." For other selected financial data including operating revenues, net income and total assets, see "Item 6. Selected Financial Data." The actual historical data in this table excludes results from the acquisition of producing and non-producing assets from Three Rivers Operating
Company LLC and certain affiliated entities (the "Three Rivers Acquisition") for periods prior to July 2012. Because of normal production declines, increased or decreased drilling activities and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2014	**2013**	**2012**
Production and operating data from continuing operations:			
Net production volumes:			
Oil (MBbl)	26,319	21,126	16,859
Natural gas (MMcf)	87,336	75,054	66,613
Total (MBoe)	40,875	33,635	27,961
Average daily production volumes:			
Oil (Bbl)	72,107	57,879	46,063
Natural gas (Mcf)	239,277	205,627	182,003
Total (Boe)	111,987	92,150	76,397
Average prices:			
Oil, without derivatives (Bbl)	$ 83.17	$ 91.76	$ 87.96
Oil, with derivatives (Bbl) (a)	$ 86.07	$ 89.79	$ 89.29
Natural gas, without derivatives (Mcf)	$ 5.39	$ 5.08	$ 5.06
Natural gas, with derivatives (Mcf) (a)	$ 5.34	$ 5.21	$ 5.07
Total, without derivatives (Boe)	$ 65.08	$ 68.97	$ 65.08
Total, with derivatives (Boe) (a)	$ 66.84	$ 68.01	$ 65.93
Operating costs and expenses per Boe:			
Lease operating expenses and workover costs	$ 8.05	$ 7.85	$ 6.90
Oil and natural gas taxes	$ 5.12	$ 5.69	$ 5.39
Depreciation, depletion and amortization	$ 23.97	$ 22.97	$ 20.56

General and administrative	$	4.99	$	5.04	$	4.79

(a) Includes the effect of cash receipts from (payments on) derivatives not designated as hedges:

	Years Ended December 31,					
(in thousands)		**2014**		**2013**		**2012**
Cash receipts from (payments on) derivatives not designated as hedges:						
Oil derivatives	$	76,335	$	(41,616)	$	22,411
Natural gas derivatives		(4,352)		9,275		1,125
Total	$	71,983	$	(32,341)	$	23,536

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash receipts from (payments on) commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

Productive Wells

The following table sets forth the number of productive oil and natural gas wells on our properties at December 31, 2014, 2013 and 2012. This table does not include wells in which we own a royalty interest only.

	Gross Productive Wells			Net Productive Wells		
	Oil	**Natural Gas**	**Total**	**Oil**	**Natural Gas**	**Total**
December 31, 2014						
Core Operating Areas:						
New Mexico Shelf	2,994	109	3,103	2,427	45	2,472
Delaware Basin	1,142	480	1,622	621	216	837
Texas Permian	2,436	44	2,480	1,147	19	1,166
Other	-	3	3	-	0	0
Total	6,572	636	7,208	4,195	280	4,475
December 31, 2013						
Core Operating Areas:						
New Mexico Shelf	2,962	102	3,064	2,416	44	2,460
Delaware Basin	785	405	1,190	424	177	601
Texas Permian	2,226	47	2,273	1,047	17	1,064
Total	5,973	554	6,527	3,887	238	4,125
December 31, 2012						
Core Operating Areas:						
New Mexico Shelf	2,719	105	2,824	2,288	46	2,334
Delaware Basin	586	404	990	311	175	486
Texas Permian	1,972	45	2,017	925	18	943
Total	5,277	554	5,831	3,524	239	3,763

Marketing Arrangements

General. We market our oil and natural gas in accordance with standard energy industry practices. The marketing effort is coordinated with our operations group as it relates to the planning and preparation of future drilling programs so that available markets can be assessed and secured. This planning also involves the coordination of access to the physical facilities necessary to connect new producing wells as efficiently as possible upon their completion.

Oil. We generally do not transport our oil, and we do not refine or process the oil we produce. A significant portion of our oil in Southeast New Mexico, primarily on the New Mexico Shelf, is connected directly to oil gathering pipelines. Most of our gathered oil from the New Mexico Shelf is utilized in a two-refinery complex in Southeast New Mexico. The New Mexico portion of our Delaware Basin production is sold to approximately twelve different oil purchasers. A significant portion of our West Texas production is on pipeline. Most of this production is sweet crude and is transported by third parties to the Cushing, Oklahoma hub or to the Gulf Coast market. The balance of our oil in these areas that is not directly connected to pipeline is (i) trucked to unloading stations on those same pipelines or (ii) railed to the Gulf Coast in lieu of transporting by pipeline. We sell the majority of the oil we produce under contracts using market-based pricing. This price is then adjusted for differentials based upon delivery location and oil quality.

Natural Gas. We consider all natural gas gathering and delivery infrastructure in the areas of our production and evaluate market options to obtain the best price reasonably available under the circumstances. We sell the majority of our natural gas under individually negotiated natural gas purchase contracts using market-based pricing. The majority of our natural gas is subject to long-term agreements that extend at least three years from the effective date of the subject contract.

The majority of the natural gas we sell is casinghead gas sold at the lease location under percentage of proceeds processing contracts. The purchaser gathers our casinghead natural gas in the field where it is produced and transports it via pipeline to a natural gas processing plant where natural gas liquid products are extracted and sold by the processor. The remaining natural gas product is residue gas, or dry gas, which is placed on residue pipeline systems available in the area. Under our percentage of proceeds contracts, we receive a percentage of the value for the extracted liquids and the residue gas. In a limited number of cases (typically dry gas production), the natural gas gathering and transportation is performed by a third-party gathering company which transports the production from the production location to the purchaser’s mainline.

Our Principal Customers

We sell our oil and natural gas production principally to marketers and other purchasers that have access to pipeline facilities. In areas where there is no practical access to pipelines, oil is transported to storage facilities by trucks and rail owned or otherwise arranged by the marketers or purchasers. Our marketing of oil and natural gas can be affected by factors beyond our control, the effects of which cannot be accurately predicted.

For 2014, revenues from oil and natural gas sales to Holly Frontier Refining and Marketing, LLC, Enterprise Crude Oil, LLC and Western Refining Company LP accounted for approximately 17 percent, 12 percent and 12 percent, respectively, of our total operating revenues. While the loss of any of these purchasers may result in a temporary interruption in sales of, or a lower price for, our production, we believe that the loss of any of these purchasers would not have a material adverse effect on our operations, as there are alternative purchasers in our producing regions.

Competition

The oil and natural gas industry in the regions in which we operate is highly competitive. We encounter strong competition from numerous parties, ranging generally from small independent producers to major integrated companies. We primarily encounter significant competition in acquiring properties, contracting for drilling, pressure pumping and workover equipment and securing trained personnel. Many of these competitors have financial, technical and personnel resources substantially larger than ours. As a result, our competitors may be able to pay more for desirable properties, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit.

In addition to competition for drilling, pressure pumping and workover equipment, we are also affected by the availability of related equipment and materials. The oil and natural gas industry periodically experiences shortages of drilling and workover rigs, equipment, pipe, materials and personnel, which can delay drilling, workover and exploration activities and cause significant price increases. The shortages of personnel make it difficult to attract and retain personnel with experience in the oil and natural gas industry and caused us to increase our general and administrative budget. We are unable to predict the timing or duration of any such shortages.

Competition is also strong for attractive oil and natural gas producing properties, undeveloped leases and drilling rights. Although we regularly evaluate acquisition opportunities and submit bids as part of our growth strategy, we do not have any current agreements, understandings or arrangements with respect to any material acquisition.

Applicable Laws and Regulations

Regulation of the Oil and Natural Gas Industry

Regulation of transportation and sale of oil*.* Prices at which sales of oil, condensate and natural gas liquids are made are not currently regulated, and sales of these products are made at negotiated prices. Nevertheless, Congress could reenact price controls in the future.

Our sales of oil are affected by the availability, terms and cost of transportation. The transportation of oil in common carrier pipelines is also subject to rate regulation. The Federal Energy Regulatory Commission (the “FERC”) regulates interstate oil pipeline transportation rates under the Interstate Commerce Act. In general, interstate oil pipeline rates must be cost-based, although settlement rates agreed to by all shippers are permitted and market-based rates may be permitted in certain circumstances. Effective January 1, 1995, the FERC implemented regulations establishing an indexing system that permits an oil pipeline, subject to limited challenges, to annually increase or decrease its transportation rates due to inflationary changes in costs using a FERC approved index, without making a cost of service filing. Every five years, the FERC reviews the appropriateness of the index in relation to industry costs. On December 16, 2010, the FERC established a new Producer Price Index for Finished Goods (the “PPI-FG”) of PPI-FG plus 2.65 percent for the five-year period beginning July 1, 2011. The basis for intrastate oil pipeline regulation, and the degree of regulatory oversight and scrutiny given to intrastate oil pipeline rates, varies from state to state. Insofar as effective interstate and intrastate rates are equally applicable to all comparable shippers, we believe that the regulation of oil transportation rates will not affect our operations in any way that is of material difference from those of our competitors.

Further, interstate and intrastate common carrier oil pipelines must provide service on a non-discriminatory basis at posted tariff rates. When oil pipelines operate at full capacity, access is governed by prorationing provisions set forth in the pipelines’ published tariffs. Accordingly, we believe that access to oil pipeline transportation services generally will be available to us to the same extent as to our competitors.

Effective November 4, 2009, pursuant to the Energy Independence and Security Act of 2007, the Federal Trade Commission (the “FTC”) issued a rule prohibiting market manipulation in the petroleum industry. The FTC rule prohibits any person, directly or indirectly, in connection with the purchase or sale of oil, gasoline or petroleum distillates at wholesale, from knowingly engaging in any act, practice or course of business, including the making of any untrue statement of material fact, that operates or would operate as a fraud or deceit upon any person, or intentionally failing to state a material fact that under the circumstances renders a statement made by such person misleading, provided that such omission distorts or is likely to distort market conditions for any such product. A violation of this rule may result in civil penalties of up to $1 million per day per violation, in addition to any applicable penalty under the Federal Trade Commission Act.

Regulation of transportation and sale of natural gas. Historically, the transportation and sale for resale of natural gas in interstate commerce have been regulated pursuant to the Natural Gas Act of 1938 (the “Natural Gas Act”), the Natural Gas Policy Act of 1978 (the “Natural Gas Policy Act”) and regulations issued under those acts by the FERC. In the past, the federal government has regulated the prices at which natural gas could be sold. While sales by producers of natural gas can currently be made at uncontrolled market prices, Congress could reenact price controls in the future, and market participants are prohibited from engaging in market manipulation. Deregulation of wellhead natural gas sales began with the enactment of the Natural Gas Policy Act. In 1989, Congress enacted the Natural Gas Wellhead Decontrol Act, which removed all Natural Gas Act and Natural Gas Policy Act price and non-price controls affecting wellhead sales of natural gas effective January 1, 1993.

The FERC regulates interstate natural gas transportation rates and service conditions, which affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas. Since 1985, the FERC has endeavored to make natural gas transportation more accessible to natural gas buyers and sellers on an open and non-discriminatory basis. The FERC has stated that open access policies are necessary to improve the competitive structure of the interstate natural gas pipeline industry and to create a regulatory framework that will put natural gas sellers into more direct contractual relations with natural gas buyers by, among other things, unbundling the sale of natural gas from the sale of transportation and storage services. Beginning in 1992, the FERC issued Order No. 636 and a series of related orders to implement its open access policies. As a result of the Order No. 636 program, the marketing and pricing of natural gas have been significantly altered. The interstate pipelines’ traditional role as wholesalers of natural gas has been eliminated and replaced by a structure under which pipelines provide transportation and storage services on an open access basis to others who buy and sell natural gas. Although these orders do not directly regulate natural gas producers, they are intended to foster increased competition within all phases of the natural gas industry.

In 2000, the FERC issued Order No. 637 and subsequent orders, which imposed a number of additional reforms designed to enhance competition in natural gas markets. Among other things, Order No. 637 effected changes in FERC regulations relating to scheduling procedures, capacity segmentation, penalties, rights of first refusal and information reporting.

In August 2005, Congress enacted the Energy Policy Act of 2005 (“EPAct 2005”). Among other matters, EPAct 2005 amends the Natural Gas Act to make it unlawful for “any entity,” including otherwise non-jurisdictional producers such as us, to use any deceptive or manipulative device or contrivance in connection with the purchase or sale of natural gas or the purchase or sale of transportation services subject to regulation by the FERC, in contravention of rules prescribed by the FERC. The FERC’s rules implementing this provision make it unlawful, in connection with the purchase or sale of natural gas subject to the jurisdiction of the FERC, or the purchase or sale of transportation services subject to the jurisdiction of the FERC, for any entity, directly or indirectly, to use or employ any device, scheme or artifice to defraud; to make any untrue statement of material fact or omit to make any such statement necessary to make the statements made not misleading; or to engage in any act or practice that operates as a fraud or deceit upon any person. EPAct 2005 also gives the FERC authority to impose civil penalties for violations of the Natural Gas Act or Natural Gas Policy Act up to $1 million per day per violation. The new anti-manipulation rule does not apply to activities that relate only to intrastate or other non-jurisdictional sales, gathering or production, but does apply to activities of otherwise non-jurisdictional entities to the extent the activities are conducted “in connection with” natural gas sales, purchases or transportation subject to FERC jurisdiction, which now includes the annual reporting requirements under Order No. 704, as described below. EPAct 2005 therefore reflects a significant expansion of the FERC’s enforcement authority. We do not anticipate we will be affected any differently than other producers of natural gas.

In December 2007, the FERC issued a rule (“Order No. 704”), as clarified in orders on rehearing, requiring that any market participant, including a producer such as us, that engages in wholesale sales or purchases of natural gas that equal or exceed 2.2 million MMBtus during a calendar year to annually report, starting May 1, 2009, such sales and purchases to the FERC. These rules are intended to increase the transparency of the wholesale natural gas markets and to assist the FERC in monitoring such markets and in detecting market manipulation. We do not anticipate that we will be affected by these rules any differently than other producers of natural gas.

We cannot accurately predict whether the FERC’s actions will achieve the goal of increasing competition in markets in which our natural gas is sold. Additional proposals and proceedings that might affect the natural gas industry are pending before the FERC and the courts. The natural gas industry historically has been very heavily regulated. Therefore, we cannot provide any assurance that the less stringent regulatory approach recently established by the FERC will continue. However, we do not believe that any action taken will affect us in a way that materially differs from the way it affects other natural gas producers.

Gathering service, which occurs upstream of jurisdictional transmission services, is regulated by the states onshore and in state waters. Although its policy is still in flux, the FERC has reclassified certain jurisdictional transmission facilities as non-jurisdictional gathering facilities, which has the tendency to increase our costs of getting natural gas to point of sale locations.

Intrastate natural gas transportation is also subject to regulation by state regulatory agencies. The basis for intrastate regulation of natural gas transportation and the degree of regulatory oversight and scrutiny given to intrastate natural gas pipeline rates and services varies from state to state. During the 2007 legislative session, the Texas State Legislature passed H.B. 3273 (the "Competition Bill") and H.B. 1920 (the "LUG Bill"). The Competition Bill gives the Railroad Commission of Texas (the "RRC") the ability to use either a cost-of-service method or a market-based method for setting rates for natural gas gathering and intrastate transportation pipelines in formal rate proceedings. It also gives the RRC specific authority to enforce its statutory duty to prevent discrimination in natural gas gathering and transportation, to enforce the requirement that parties participate in an informal complaint process and to penalize purchasers, transporters, and gatherers for taking discriminatory actions against shippers and sellers. The Competition Bill also provides producers with the unilateral option to determine whether or not confidentiality provisions are included in a contract to which a producer is a party for the sale, transportation or gathering of natural gas. The LUG Bill modifies the informal complaint process at the RRC with procedures unique to lost and unaccounted for natural gas issues. It extends the types of information that can be requested, provides producers with an annual audit right, and provides the RRC with the authority to make determinations and issue orders in specific situations. Both the Competition Bill and the LUG Bill became effective on September 1, 2007, and the RRC rules implementing the RRC's authority pursuant to the bills became effective on April 28, 2008.

Insofar as such regulation within a particular state will generally affect all intrastate natural gas shippers within the state on a comparable basis, we believe that the regulation of similarly situated intrastate natural gas transportation in any states in which we operate and ship natural gas on an intrastate basis will not affect our operations in any way that is of material difference from those of our competitors. Like the regulation of interstate transportation rates, the regulation of intrastate transportation rates affects the marketing of natural gas that we produce, as well as the revenues we receive for sales of our natural gas.

Regulation of production. The production of oil and natural gas is subject to regulation under a wide range of local, state and federal statutes, rules, orders and regulations. Federal, state and local statutes and regulations require permits for drilling operations, drilling bonds and reports concerning operations. All of the states in which we own and operate properties have regulations governing conservation matters, including provisions for the unitization or pooling of oil and natural gas properties, the establishment of maximum allowable rates of production from oil and natural gas wells, the regulation of well spacing, and the plugging and abandonment of wells. The effect of these regulations is to limit the amount of oil and natural gas that we can produce from our wells and to limit the number of wells or the locations at which we can drill, although we can apply for exceptions to such regulations or to have reductions in well spacing. Moreover, each state generally imposes a production or severance tax with respect to the production and sale of oil, natural gas and natural gas liquids within its jurisdiction. The failure to comply with these rules and regulations can result in substantial penalties. Our competitors in the oil and natural gas industry are subject to the same regulatory requirements and restrictions that affect our operations.

Environmental, Health and Safety Matters

General. Our operations are subject to stringent and complex federal, state and local laws and regulations governing environmental protection as well as the discharge of materials into the environment. These laws, rules and regulations may, among other things:

- require the acquisition of various permits before drilling commences;

- restrict the types, quantities and concentration of various substances that can be released into the environment in connection with oil and natural gas drilling and production and saltwater disposal activities;

- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other protected areas; and

• require remedial measures to mitigate pollution from former and ongoing operations, such as requirements to close pits and plug abandoned wells.

These laws, rules and regulations may also restrict the rate of oil and natural gas production below the rate that would otherwise be possible. The regulatory burden on the oil and natural gas industry increases the cost of doing business in the industry and consequently affects profitability. Additionally, environmental laws and regulations are revised frequently, and any changes that result in more stringent and costly waste handling, disposal and cleanup requirements for the oil and natural gas industry could have a significant impact on our operating costs.

The following is a summary of some of the existing laws, rules and regulations to which our business is subject.

Waste handling. The Resource Conservation and Recovery Act ("RCRA") and comparable state statutes regulate the generation, transportation, treatment, storage, disposal and cleanup of hazardous and non-hazardous wastes. Pursuant to regulatory guidance issued by the federal Environmental Protection Agency (the "EPA"), the individual states administer some or all of the provisions of RCRA, sometimes in conjunction with their own, more stringent requirements. Drilling fluids, produced waters, and most of the other wastes associated with the exploration, development, and production of oil or natural gas are currently regulated under RCRA's non-hazardous waste provisions. However, it is possible that certain oil and natural gas exploration and production wastes now classified as non-hazardous could be classified as hazardous wastes in the future. Any such change could result in an increase in our costs to manage and dispose of wastes, which could have a material adverse effect on our results of operations and financial position.

Comprehensive Environmental Response, Compensation and Liability Act. The Comprehensive Environmental Response Compensation and Liability Act ("CERCLA"), also known as the Superfund law, imposes joint and several liability, without regard to fault or legality of conduct, on classes of persons who are considered to be responsible for the release of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and anyone who disposed or arranged for the disposal of a hazardous substance released at the site. Under CERCLA, such persons may be subject to joint and several liability for the costs of cleaning up the hazardous substances that have been released into the environment, for damages to natural resources and for the costs of certain health studies. In addition, it is not uncommon for neighboring landowners and other third parties to file claims for personal injury and property damage allegedly caused by the hazardous substances released into the environment.

We currently own, lease, or operate numerous properties that have been used for oil and natural gas exploration and production for many years. Although we believe that we have utilized operating and waste disposal practices that were standard in the industry at the time, hazardous substances, wastes or hydrocarbons may have been released on or under the properties owned or leased by us, or on or under other locations, including off-site locations, where such substances have been taken for disposal. In addition, some of our properties have been operated by third parties or by previous owners or operators whose treatment and disposal of hazardous substances, wastes or hydrocarbons were not under our control. These properties and the substances disposed or released on them may be subject to CERCLA, RCRA and analogous state laws. Under such laws, we could be required to remove previously disposed substances and wastes, remediate contaminated property, or perform remedial operations to prevent future contamination.

Water discharges. The federal Water Pollution Control Act (the “Clean Water Act”) and analogous state laws, impose restrictions and strict controls with respect to the discharge of pollutants, including spills and leaks of oil and other substances, into waters of the United States. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or an analogous state agency. Spill prevention, control and countermeasure requirements under federal law require appropriate containment berms and similar structures to help prevent the contamination of navigable waters in the event of a petroleum hydrocarbon tank spill, rupture or leak. In addition, the Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities. The Clean Water Act also prohibits the discharge of dredge and fill material in regulated waters, including wetlands, unless authorized by permit. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with discharge permits or other requirements of the Clean Water Act and analogous state laws and regulations.

Safe Drinking Water Act. Our oil and natural gas exploration and production operations generate produced water, drilling muds, and other waste streams, some of which may be disposed via injection in underground wells situated in non-producing subsurface formations. The drilling and operation of these injection wells are regulated by the Safe Drinking Water Act (the “SDWA”). The Underground Injection Well Program under the SDWA requires that we obtain permits from the EPA or delegated state agencies for our disposal wells, establishes minimum standards for injection well operations, restricts the types and quantities of fluids that may be injected and prohibits the migration of fluid containing any contaminants into underground sources of drinking water. Any leakage from the subsurface portions of the injection wells may cause degradation of freshwater, potentially resulting in cancellation of operations of a well, imposition of fines and penalties from governmental agencies, incurrence of expenditures for remediation of affected resources, and imposition of liability by landowners or other parties claiming damages for alternative water supplies, property damages, and personal injuries. While we believe that we have obtained the necessary permits from the applicable regulatory agencies for our underground injection wells and that we are in substantial compliance with permit conditions and federal and state rules, any changes in the laws or regulations or the inability to obtain permits for new injection wells in the future may affect our ability to dispose of produced waters and would ultimately increase the cost of our operations, which costs could be significant. For example, the RRC recently adopted new permit rules for injection wells to address these seismic activity concerns within the state. Among other things, the rules require companies seeking permits for disposal wells to provide seismic activity data in permit applications, provide for more frequent monitoring and reporting for certain wells, and allow the RRC to modify, suspend, or terminate permits on grounds that a disposal well is likely to be, or determined to be, causing seismic activity. Furthermore, in response to recent seismic events near underground injection wells used for the disposal of oil and gas-related wastewaters, federal and some state agencies have begun investigating whether such wells have caused increased seismic activity, and some states have shut down or imposed moratoria on the use of such injection wells. If new regulatory initiatives are implemented that restrict or prohibit the use of underground injection wells in areas where we rely upon the use of such wells in our operations, our costs to operate may significantly increase, and our ability to continue production may be delayed or limited, which could have a material adverse effect on our results of operations and financial position.

Air emissions. The federal Clean Air Act (the “CAA”), and comparable state laws regulate emissions of various air pollutants through air emissions permitting programs and the imposition of other requirements. Federal and state regulatory agencies can impose administrative, civil and criminal penalties for non-compliance with air permits or other requirements of the CAA and associated state laws and regulations. In addition, the EPA has developed, and continues to develop, stringent regulations governing emissions of toxic air pollutants at specified sources.

For example, in August 2012, the EPA adopted new rules that make all oil and gas operations (production, processing, transmission, storage and distribution) subject to regulation under the New Source Performance Standards ("NSPS") and National Emission Standards for Hazardous Air Pollutants ("NESHAPS") programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all "other" fractured and refractured gas wells. All three subcategories of wells are currently required to route flow back emissions to a gathering line or be captured and combusted using a combustion device, such as a flare. However, the wells in the "other" category are required to use the reduced emission completion ("REC") techniques developed in EPA's Natural Gas STAR program. Further, the new NESHAPS regulations impose maximum achievable control technology ("MACT") standards for those glycol dehydrators and storage vessels at major sources of hazardous air pollutants not currently subject to MACT standards. Compliance with these requirements could increase our costs of development and production; however, we do not believe that such requirements will have a material adverse effect on our operations.

Climate change. In December 2009, the EPA determined that emissions of carbon dioxide, methane and other "greenhouse gases", or GHGs, present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA initially adopted two sets of rules regulating GHG emissions under the CAA, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources. The EPA's rules relating to emissions of GHGs are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. Also, the EPA has adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including certain onshore oil and natural gas facilities, on an annual basis.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, almost one-half of the states have taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances, or to comply with new regulatory or reporting requirements. For example, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produce. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

Hydraulic fracturing. Hydraulic fracturing is an important and common practice that is used to stimulate production of oil and/or natural gas from dense subsurface rock formations. The hydraulic fracturing process involves the injection of water, sand, and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. We routinely use hydraulic fracturing as part of our operations. The process is typically regulated by state oil and natural gas commissions, but the EPA has asserted federal regulatory authority pursuant to the SDWA over certain hydraulic fracturing activities involving the use of diesel. In addition, in May 2014, the EPA issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act. To date, no other action has been taken. At the state level, several states have adopted or are considering legal requirements that could impose more stringent permitting, disclosure, and well construction requirements on hydraulic fracturing activities. For example, New Mexico adopted hydraulic fracturing fluid disclosure requirements in February 2012 and in May 2013, and the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources in May

2013. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

In addition, certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic fracturing practices. The White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices. Additionally, the EPA is performing a study of the potential environmental effects of hydraulic fracturing on drinking water and groundwater resources, and a draft report is expected to be available for public comment and peer review the first half of 2015. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards sometime in 2015. Other governmental agencies, including the United States Department of Energy and the United States Department of the Interior, are evaluating various other aspects of hydraulic fracturing. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the federal SDWA or other regulatory mechanisms.

To our knowledge, there have been no citations, suits, or contamination of potable drinking water arising from our fracturing operations. We do not have insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations; however, we believe our general liability and excess liability insurance policies may cover third-party claims related to hydraulic fracturing operations and associated legal expenses in accordance with, and subject to, the terms of such policies. If new laws or regulations significantly restrict hydraulic fracturing activities or impose burdens on new permitting or operating requirements, our ability to utilize hydraulic fracturing may be curtailed, and this may in turn reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

Endangered species. The federal Endangered Species Act (the "ESA") and analogous state laws regulate activities that could have an adverse effect on threatened or endangered species. Some of our drilling operations are conducted in areas where protected species are known to exist. In these areas, we may be obligated to develop and implement plans to avoid potential adverse impacts to protected species, and we may be prohibited from conducting drilling operations in certain locations or during certain seasons, such as breeding and nesting seasons, when our operations could have an adverse effect on the species. It is also possible that a federal or state agency could order a complete halt to drilling activities in certain locations if it is determined that such activities may have a serious adverse effect on a protected species. The presence of a protected species in areas where we perform drilling activities could impair our ability to timely complete drilling and developmental operations and could adversely affect our future production from those areas. Moreover, as a result of a settlement approved by the U.S. District Court for the District of Columbia in September 2011, the U.S. Fish and Wildlife Service is required to make a determination on listing of numerous species as endangered or threatened under the ESA before the completion of the agency's 2017 fiscal year. The designation of previously unprotected species as threatened or endangered in areas where we or our oil and natural gas exploration and production customers operate could cause us or our customers to incur increased costs arising from species protection measures and could result in delays or limitations in our customers' performance of operations, which could reduce demand for our midstream services.

National Environmental Policy Act. Oil and natural gas exploration and production activities on federal lands are subject to the National Environmental Policy Act ("NEPA"). NEPA requires federal agencies, including the Department of Interior, to evaluate major agency actions having the potential to significantly impact the environment. In the course of such evaluations, an agency will prepare an environmental assessment that assesses the potential direct, indirect and cumulative impacts of a proposed project and, if necessary, will prepare a more detailed environmental impact statement that may be made available for public review and comment. All of our current exploration and production activities, as well as proposed exploration and development plans, on federal lands require governmental permits that are subject to the requirements of NEPA. This process has the potential to delay or even halt development of some of our oil and natural gas projects.

OSHA and other laws and regulations. We are subject to the requirements of the federal Occupational Safety and Health Act ("OSHA"), and comparable state statutes. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes require that we organize and/or disclose information about hazardous materials used or produced in our operations. Also, pursuant to OSHA, the Occupational Safety and Health Administration has established a variety of standards relating to workplace exposure to hazardous substances and employee health and safety. We believe that we are in substantial compliance with the applicable requirements of OSHA and comparable laws.

We believe that we are in substantial compliance with existing environmental laws and regulations applicable to our current operations and that our continued compliance with existing requirements will not have a material adverse impact on our financial condition and results of operations. For instance, we did not incur any material capital expenditures for remediation or pollution control activities during 2014. Additionally, as of the date of this report, we are not aware of any environmental issues or claims that will require material capital expenditures during 2015. However, we cannot assure you that the passage or application of more stringent laws or regulations in the future will not have a negative impact on our financial position or results of operations.

Our Employees

Our corporate headquarters are located at One Concho Center, 600 West Illinois Avenue, Midland, Texas 79701. We also maintain various field offices in Texas and New Mexico. At December 31, 2014, we had 1,022 employees, 338 of whom were employed in field operations. Our future success will depend partially on our ability to attract, retain and motivate qualified personnel. We are not a party to any collective bargaining agreements and have not experienced any strikes or work stoppages. We consider our relations with our employees to be good. We also utilize the services of independent contractors to perform various field and other services.

Available Information

We file or furnish annual, quarterly and current reports, proxy statements and other documents with the United States Securities and Exchange Commission (the “SEC”) under the Exchange Act. The public may read and copy any materials that we file or furnish 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. Also, the SEC maintains a website that contains reports, proxy and information statements, and other information regarding issuers, including us, that file or furnish electronically 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 through our website, *www.concho.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 electronically file such material with, or furnish it to, the SEC.

Non-GAAP Financial Measures and Reconciliations

PV-10

PV-10 is derived from the standardized measure of discounted future net cash flows, which is the most directly comparable GAAP financial measure. PV-10 is a computation of the standardized measure of discounted future net cash flows on a pre-tax basis. PV-10 is equal to the standardized measure of discounted future net cash flows at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the standardized measure of discounted future net cash flows. Our PV-10 measure and the standardized measure of discounted future net cash flows do not purport to present the fair value of our oil and natural gas reserves.

The following table provides a reconciliation of PV-10 to the standardized measure of discounted future net cash flows at December 31, 2014, 2013 and 2012:

	December 31,		
(in millions)	**2014**	**2013**	**2012**
PV-10	$ 11,384.8	$ 9,029.5	$ 8,327.0
Present value of future income taxes discounted at 10%	(3,362.0)	(2,785.1)	(2,538.9)
Standardized measure of discounted future net cash flows	$ 8,022.8	$ 6,244.4	$ 5,788.1

EBITDAX

We define EBITDAX as net income, plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) bad debt expense, (7) (gain) loss on derivatives not designated as hedges, (8) cash receipts from (payments on) derivatives not designated as hedges, (9) loss on disposition of assets, net, (10) interest expense, (11) loss on extinguishment of debt, (12) federal and state income taxes from continuing operations and (13) similar items listed above that are presented in discontinued operations. EBITDAX is not a measure of net income or cash flow as determined by GAAP.

Our EBITDAX measure provides additional information which may be used to better understand our operations, and it is also a material component of one of the financial covenants under our credit facility. EBITDAX is one of several metrics that we use as a supplemental financial measurement in the evaluation of our business and should not be considered as an alternative to, or more meaningful than, net income, as an indicator of our operating performance. Certain items excluded from EBITDAX are significant components in understanding and assessing a company's financial performance, such as a company's cost of capital and tax structure, as well as the historic cost of depreciable and depletable assets. EBITDAX, as used by us, may not be comparable to similarly titled measures reported by other companies. We believe that EBITDAX is a widely followed measure of operating performance and is one of many metrics used by our management team and by other users of our consolidated financial statements, including by lenders pursuant to a covenant in our credit facility. For example, EBITDAX can be used to assess our operating performance and return on capital in comparison to other independent exploration and production companies without regard to financial or capital structure, and to assess the financial performance of our assets and our company without regard to capital structure or historical cost basis. Further, under our credit facility, an event of default could arise if we were not able to satisfy and remain in compliance with specified financial ratios, including the maintenance of a quarterly ratio of total debt to consolidated last twelve months EBITDAX of no greater than 4.25 to 1.0. Non-compliance with this ratio could trigger an event of default under our credit facility, which then could trigger an event of default under our indentures.

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

	Years Ended December 31,				
(in thousands)	**2014**	**2013**	**2012**	**2011**	**2010**
Net income	$ 538,175	$ 251,003	$ 431,689	$ 548,137	$ 204,370
Exploration and abandonments	284,821	109,549	39,840	11,394	10,130
Depreciation, depletion and amortization	979,740	772,608	575,128	400,022	211,487
Accretion of discount on asset retirement obligations	7,072	6,047	4,187	2,444	1,079
	447,151	65,375	-	439	11,614

Impairments of long-lived assets					
Non-cash stock-based compensation	47,130	35,078	29,872	19,271	12,931
Bad debt expense	-	-	-	-	870
(Gain) loss on derivatives not designated as hedges	(890,917)	123,652	(127,443)	23,350	87,325
Cash receipts from (payments on) derivatives not designated as hedges	71,983	(32,341)	23,536	(84,854)	(13,824)
Loss on disposition of assets, net	9,308	1,268	372	1,139	58
Interest expense	216,661	218,581	182,705	118,360	60,087
Loss on extinguishment of debt	4,316	28,616	-	-	-
Income tax expense from continuing operations	317,785	118,237	251,041	261,800	101,613
Discontinued operations	-	(12,081)	64,701	(26,343)	55,254
EBITDAX	$ 2,033,225	$ 1,685,592	$ 1,475,628	$ 1,275,159	$ 742,994

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Item 1A. Risk Factors

You should consider carefully the following risk factors together with all of the other information included in this report and other reports filed with the SEC before investing in our securities. If any of the following risks were actually to occur, our business, financial condition or results of operations could be materially adversely affected. In that case, the trading price of our securities could decline and you could lose all or part of your investment.

Risks Related to Our Business

Oil, natural gas and natural gas liquid prices are volatile. A decline in oil, natural gas and natural gas liquid prices could adversely affect our financial position, financial results, cash flow, access to capital and ability to grow.

Our future financial condition, revenues, results of operations, rate of growth and the carrying value of our oil and natural gas properties depend primarily upon the prices we receive for our oil and natural gas production and the prices prevailing from time to time for oil, natural gas and natural gas liquids. Oil, natural gas, and natural gas liquid prices historically have been volatile, and are likely to continue to be volatile in the future, especially given current geopolitical conditions. This price volatility also affects the amount of cash flow we have available for capital expenditures and our ability to borrow money or raise additional capital. The prices for oil, natural gas and natural gas liquids are subject to a variety of factors beyond our control, including:

- the level of consumer demand for oil, natural gas and natural gas liquids;
- the domestic and foreign supply of oil, natural gas, and natural gas liquids;
- inventory levels of Cushing, Oklahoma, the benchmark for WTI oil prices;
- liquefied natural gas deliveries to and from the United States;
- commodity processing, gathering and transportation availability and the availability of refining capacity;
- the price and level of imports of foreign oil and natural gas;

- the ability of the members of the Organization of Petroleum Exporting Countries and other oil exporting nations to agree to and maintain oil price and production controls;

- domestic and foreign governmental regulations and taxes;

- the price and availability of alternative fuel sources;

- weather conditions;

- political conditions or hostilities in oil and natural gas producing regions, including the Middle East, Africa and South America;

- technological advances affecting energy consumption and energy supply;

- effect of energy conservation efforts;

- variations between product prices at sales points and applicable index prices; and

- worldwide economic conditions.

Furthermore, oil and natural gas prices continued to be volatile in 2014. For example, the NYMEX oil prices in 2014 ranged from a high of $107.26 to a low of $53.27 per Bbl and the NYMEX natural gas prices in 2014 ranged from a high of $6.15 to a low of $2.89 per MMBtu. Further, the NYMEX oil prices and NYMEX natural gas prices reached lows of $44.45 per Bbl and $2.58 per MMBtu, respectively, during the period from January 1, 2015 to February 24, 2015.

Historically, approximately 55 to 80 percent of our total natural gas revenues have been derived from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. Because of our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues historically, our realized natural gas price (excluding the effects of derivatives) has reflected a price greater than the related NYMEX natural gas price. The Mont Belvieu prices for a blended barrel of natural gas liquids in 2014 ranged from a high of $43.76 per Bbl to a low of $19.99 per Bbl. Further, the Mont Belvieu price for a blended barrel of natural gas liquids for January 2015 was $18.08 per Bbl.

Declines in oil, natural gas and natural gas liquid prices would not only reduce our revenue, but could also reduce the amount of oil and natural gas that we can produce economically. This in turn would lower the amount of oil and natural gas reserves we could recognize and, as a result, could have a material adverse effect on our financial condition and results of operations. If the oil and natural gas industry experiences significant price declines, we may, among other things, be unable to maintain or increase our borrowing capacity, repay current or future indebtedness or obtain additional capital on attractive terms, all of which can adversely affect the value of our securities.

Future price declines could result in a reduction in the carrying value of our proved oil and natural gas properties, which could adversely affect our results of operations.

Declines in commodity prices may result in having to make substantial downward adjustments to our estimated proved reserves. If this occurs, or if our estimates of production or economic factors change, accounting rules may require us to write-down, as a noncash charge to earnings, the carrying value of our proved oil and natural gas properties for impairments. We are required to perform impairment tests on proved assets whenever events or changes in circumstances warrant a review of our proved oil and natural gas properties. To the extent such tests indicate a reduction of the estimated useful life or estimated future cash flows of our oil and natural gas properties, the carrying value may not be recoverable and therefore require a write-down. We may incur impairment charges in the future, which could materially adversely affect our results of operations in the period incurred.

Approximately 40.9 percent of our total estimated proved reserves at December 31, 2014 were undeveloped, and those reserves may not ultimately be developed.

At December 31, 2014, approximately 40.9 percent of our total estimated proved reserves were undeveloped. Recovery of undeveloped reserves requires significant capital expenditures and successful drilling. Our reserve data assumes that we can and will make these expenditures and conduct these operations successfully. These assumptions, however, may not prove correct. Our reserve report at December 31, 2014 includes estimates of total future development costs over the next five years associated with our proved undeveloped reserves of approximately $4.2 billion. If we choose not to spend the capital to develop these reserves, or if we are not otherwise able to successfully develop these reserves, we will be required to write-off these reserves. In addition, under the SEC's reserve rules, because proved undeveloped reserves may be booked only if they relate to wells planned to be drilled within five years of the date of booking, we may be required to write-off any proved undeveloped reserves that are not developed within this five-year timeframe. For example, as of December 31, 2014, we wrote-off 36.2 MMBoe of proved undeveloped reserves because we have deferred development outside the five-year window as a result of reduced commodity prices. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities.

Drilling for and producing oil and natural gas are high-risk activities with many uncertainties that could cause our expenses to increase or production volumes to decrease, which would reduce our cash flows.

Our future financial condition and results of operations will depend on the success of our exploration and production activities. Our oil and natural gas exploration and production activities are subject to numerous risks beyond our control, including the risk that drilling will not result in commercially viable oil or natural gas production. Our decisions to purchase, explore, develop or otherwise exploit prospects or properties will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Our cost of drilling, completing, equipping and operating wells is often uncertain before drilling commences. Overruns in budgeted expenditures are common risks that can make a particular project uneconomical or less economical than forecasted. Further, many factors may curtail, delay or cancel drilling, including the following:

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

- pressure or irregularities in geological formations;

- shortages of or delays in obtaining equipment and qualified personnel or in obtaining water for hydraulic fracturing activities;
- equipment failures or accidents;
- adverse weather conditions;
- environmental hazards, such as natural gas leaks, oil spills, pipeline and tank ruptures, encountering naturally occurring radioactive materials, and unauthorized discharges of brine, well stimulation and completion fluids, toxic gases or other pollutants into the surface and subsurface environment;
- reductions in oil, natural gas and natural gas liquid prices;
- limited availability of financing at acceptable terms;
- surface access restrictions;
- loss of title or other title related issues;
- oil, natural gas liquids or natural gas gathering, transportation and processing availability restrictions or limitations; and
- limitations in the market for oil, natural gas and natural gas liquids.

Prolonged decreases in our drilling program may require us to pay certain non-use fees or impact our ability to comply with certain contractual requirements.

Oil prices declined substantially during the second half of 2014 and have continued to decline in 2015. In the event that oil and natural gas prices remain depressed for a sustained period, or continue to further decline, we may experience significant decreases in drilling activity. Due to the nature of our drilling programs and the oil and natural gas industry generally, we are a party to certain agreements that require us to meet various contractual obligations or require us to utilize a certain amount of goods or services, including, but not limited to, water commitments, throughput volume commitments and power commitments. In the event that oil and natural gas prices remain depressed, and as a result continue to reduce the demand for drilling and production, this could lead to a decrease in our drilling activity and production levels, which could, in turn, require us to pay for unutilized goods or services or impact our ability to meet these contractual obligations.

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

Hydraulic fracturing is an important and common practice that is used to stimulate production of hydrocarbons from tight formations. We routinely utilize hydraulic fracturing techniques in many of our drilling and completion programs. The process involves the injection of water, sand and chemicals under pressure into the formation to fracture the surrounding rock and stimulate production. The process is typically regulated by state oil and natural gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel additives under the SDWA’s Underground Injection Control Program. For example, in May 2014, the EPA issued an Advance Notice of Proposed Rulemaking to collect data on chemicals used in hydraulic fracturing operations under Section 8 of the Toxic Substances Control Act. To date, no other action has been taken. Also, the U.S. Department of the Interior’s Bureau of Land Management issued proposed rules in May 2013 that would update existing regulation of hydraulic fracturing activities on federal lands, including requirements for chemical disclosure, well bore integrity and handling of flowback water. A final version of these rules may be adopted in 2015.

Further, in August 2012, the EPA adopted new rules that make all oil and gas operations (production, processing, transmission, storage and distribution) subject to regulation under the NSPS and NESHAPS programs. With regards to production activities, these final rules require, among other things, the reduction of volatile organic compound emissions from three subcategories of fractured and refractured gas wells for which well completion operations are conducted: wildcat (exploratory) and delineation gas wells; low reservoir pressure non-wildcat and non-delineation gas wells; and all “other” fractured and refractured gas wells. All three subcategories of wells are currently required to route flow back emissions to a gathering line or be captured and combusted using a combustion device, such as a flare. However, wells in the “other” category are required to use the REC techniques developed in EPA’s Natural Gas STAR program.

In addition, Congress from time to time has considered the adoption of legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the hydraulic fracturing process. Certain states, including Texas and New Mexico, have adopted, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic-fracturing operations or otherwise seek to ban fracturing activities altogether. For example, New Mexico adopted hydraulic fracturing fluid disclosure requirements in February 2012, and in May 2013 the RRC adopted new rules governing well casing, cementing and other standards for ensuring that hydraulic fracturing operations do not contaminate nearby water resources in May 2013. We believe that we follow applicable standard industry practices and legal requirements for groundwater protection in our hydraulic fracturing activities. Nonetheless, if new or more stringent federal, state, or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we operate, we could incur potentially significant added costs to comply with such requirements, experience delays or curtailment in the pursuit of exploration, development, or production activities, and perhaps even be precluded from drilling wells.

Certain governmental reviews are either underway or being proposed that focus on environmental aspects of hydraulic-fracturing practices. For example, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic-fracturing practices. Additionally, the EPA is performing a study of the potential environmental impacts of hydraulic fracturing activities on drinking water and groundwater resources and a draft report is expected to be available for public comment and peer review in the first half of 2015. Moreover, the EPA is developing effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities and plans to propose these standards sometime in 2015. Also, the United States Department of Energy is conducting an investigation into practices the agency could recommend to better protect the environment from drilling using hydraulic-fracturing completion methods. These ongoing or proposed studies could spur initiatives to further regulate hydraulic fracturing under the SDWA or other regulatory mechanism.

If new laws or regulations that significantly restrict hydraulic fracturing are adopted, such laws could make it more difficult or costly for us to perform fracturing to stimulate production from tight formations. In addition, if hydraulic fracturing becomes regulated at the federal level as a result of federal legislation or regulatory initiatives by the EPA, our fracturing activities could become subject to additional permitting requirements and could also result in permitting delays and potential cost increases. Restrictions on hydraulic fracturing could also reduce the amount of oil and natural gas that we are ultimately able to produce from our reserves.

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 local land owners and other sources for use in our operations. During 2014, extreme drought conditions persisted in West Texas and Southeast New Mexico. 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.

Estimates of proved reserves and future net cash flows are not precise. The actual quantities of our proved reserves and our future net cash flows may prove to be lower than estimated.

Numerous uncertainties exist in estimating quantities of proved reserves and future net cash flows therefrom. Our estimates of proved reserves and related future net cash flows are based on various assumptions, which may ultimately prove to be inaccurate.

Petroleum engineering is a subjective process of estimating accumulations of oil and natural gas that cannot be measured in an exact manner. Estimates of economically recoverable oil and natural gas reserves and of future net cash flows depend upon a number of variable factors and assumptions, including the following:

- historical production from the area compared with production from other producing areas;

- the assumed effects of regulations by governmental agencies;

- the quality, quantity and interpretation of available relevant data;

- assumptions concerning future commodity prices; and

- assumptions concerning future operating costs; severance, ad valorem and excise taxes; development costs; and workover and remedial costs.

Because all reserve estimates are to some degree subjective, each of the following items, or other items not identified below, may differ materially from those assumed in estimating reserves:

- the quantities of oil and natural gas that are ultimately recovered;

- the production and operating costs incurred;

- the amount and timing of future development expenditures; and

- future commodity prices.

Furthermore, different reserve engineers may make different estimates of reserves and cash flows based on the same data. Our actual production, revenues and expenditures with respect to reserves will likely be different from estimates and the differences may be material.

As required by the SEC, the estimated discounted future net cash flows from proved reserves are based on the average previous twelve months first-of-month prices preceding the date of the estimate and costs as of the date of the estimate, while actual future prices and costs may be materially higher or lower. Actual future net cash flows also will be affected by factors such as:

- the amount and timing of actual production;

- levels of future capital spending;
- increases or decreases in the supply of or demand for oil, natural gas liquids and natural gas; and
- changes in governmental regulations or taxation.

Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. Therefore, the estimates of discounted future net cash flows in this report should not be construed as accurate estimates of the current market value of our proved reserves.

Our business requires substantial capital expenditures. We may be unable to obtain needed capital or financing on satisfactory terms or at all, which could lead to a decline in our oil and natural gas reserves.

The oil and natural gas industry is capital intensive. We make and expect to continue to make substantial capital expenditures for the acquisition, exploration and development of oil and natural gas reserves. At December 31, 2014, debt outstanding under our credit facility was $139.5 million (and total debt at December 31, 2014 was $3.5 billion), and we had approximately $2.4 billion of unused commitments under our credit facility. Based on our current ratio as defined in our credit facility as part of our financial covenants, at December 31, 2014, our additional borrowings would be limited to approximately $1.6 billion. Expenditures for acquisition, exploration and development of oil and natural gas properties are the primary use of our capital resources. We incurred approximately $2.9 billion in acquisition, exploration and development activities (excluding asset retirement obligations) during the year ended December 31, 2014. Under our 2015 capital budget, we currently intend to invest approximately $2.0 billion for exploration and development activities and customary acquisition of leasehold acreage.

We intend to finance our future capital expenditures, other than significant acquisitions, through cash flow from operations and through borrowings under our credit facility; however, our financing needs may require us to alter or increase our capitalization substantially through the issuance of debt or equity securities. The issuance of additional equity securities could have a dilutive effect on the value of our common stock. Additional borrowings under our credit facility or the issuance of additional debt securities will require that a greater portion of our cash flow from operations be used for the payment of interest and principal on our debt, thereby reducing our ability to use cash flow to fund working capital, capital expenditures and acquisitions. In addition, our credit facility imposes certain limitations on our ability to incur additional indebtedness other than indebtedness under our credit facility. If we desire to issue additional debt securities other than as expressly permitted under our credit facility, we will be required to seek the consent of the lenders in accordance with the requirements of the credit facility, which consent may be withheld by the lenders at their discretion. If we incur certain additional indebtedness, our borrowing base under our credit facility may be reduced. Additional financing also may not be available on acceptable terms or at all. In the event additional capital resources are unavailable, we may curtail drilling, development and other activities or be forced to sell some of our assets on an untimely or unfavorable basis.

Our cash flow from operations and access to capital are subject to a number of variables, including:

- our proved reserves;
- the level of oil and natural gas we are able to produce from existing wells;
- the prices at which our commodities are sold;
- the costs of producing oil and natural gas;
- global credit and securities markets;
- the ability and willingness of lenders and investors to provide capital and the cost of the capital; and
- our ability to acquire, locate and produce new reserves.

If our revenues or the borrowing base under our credit facility decrease as a result of lower commodity prices, operating difficulties, declines in reserves, lending requirements or regulations, or for any other reason, we may have limited ability to obtain the capital necessary to sustain our operations at current levels. As a result, we may require additional capital to fund our operations, and we may not be able to obtain debt or equity financing on terms acceptable to us, if at all, to satisfy our capital requirements. If cash generated from operations or borrowings available under our credit facility is not sufficient to meet our capital requirements, the failure to obtain additional financing could result in a curtailment of our operations relating to the development of our prospects, which in turn could lead to a decline in our oil and natural gas reserves, and could adversely affect our production, revenues and results of operations.

Declining general economic, business or industry conditions could have a material adverse effect on our results of operations.

In recent years, the global economic downturn, particularly with respect to the U.S. economy, and the global financial and credit market disruptions have reduced the availability of liquidity and credit to fund the continuation and expansion of industrial business operations worldwide resulting in a slowdown in economic activity. This has reduced worldwide demand for energy and resulted in lower commodity prices.

Lower commodity prices will reduce our cash flows and borrowing ability. We may be unable to obtain needed capital or financing on satisfactory terms, which could lead to a decline in our reserves as existing reserves are depleted. Lower commodity prices may also reduce the amount of oil and natural gas that we can produce economically, which could ultimately decrease our net revenue and profitability.

We have substantial indebtedness and may incur substantially more debt. Higher levels of indebtedness make us more vulnerable to economic downturns and adverse developments in our business.

We had approximately $3.5 billion of outstanding debt at December 31, 2014. At December 31, 2014, the borrowing base under our credit facility was $3.25 billion and commitments from our bank group totaled $2.5 billion, of which approximately $2.4 billion was unused commitments. Based on our current ratio as defined in our credit facility as part of our financial covenants, at December 31, 2014, our additional borrowings would be limited to approximately $1.6 billion.

As a result of our indebtedness, we will need to use a portion of our cash flow to pay interest, which will reduce the amount we will have available to fund our operations and other business activities and could limit our flexibility in planning for or reacting to changes in our business and the industry in which we operate. Our indebtedness under our credit facility is at a variable interest rate, and so a rise in interest rates will generate greater interest expense to the extent we do not have applicable interest rate fluctuation hedges. The amount of our debt may also cause us to be more vulnerable to economic downturns and adverse developments in our business.

We may incur substantially more debt in the future. The indentures governing our senior notes contain restrictions on our incurrence of additional indebtedness. These restrictions, however, are subject to a number of qualifications and exceptions, and under certain circumstances, we could incur substantial additional indebtedness in compliance with these restrictions. Moreover, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness under the indentures.

Our ability to meet our debt obligations and other expenses will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors, many of which we are unable to control. If our cash flow is not sufficient to service our debt, we may be required to refinance debt, sell assets or sell additional equity on terms that we may not find attractive if it may be done at all. Further, our failure to comply with the financial and other restrictive covenants relating to our indebtedness could result in a default under that indebtedness, which could adversely affect our business, financial condition and results of operations.

Our lenders can limit our borrowing capabilities, which may materially impact our operations.

At December 31, 2014, we had approximately $139.5 million of outstanding debt under our credit facility, and our borrowing base was $3.25 billion and commitments from our bank group totaled $2.5 billion. The borrowing base under our credit facility is redetermined annually based upon a number of factors, including commodity prices and reserve levels. In addition, between redeterminations we and, if requested by 66 2/3 percent of our lenders, our lenders, may each request one special redetermination. Upon a redetermination, our borrowing base could be substantially reduced, and in the event the amount outstanding under our credit facility at any time exceeds the borrowing base at such time, we may be required to repay a portion of our outstanding borrowings. We expect to utilize cash flow from operations, bank borrowings, debt and equity financings and asset sales to fund our acquisition, exploration and development activities. A reduction in our borrowing base could limit our activities. In addition, we may significantly alter our capitalization in order to make future acquisitions or develop our properties. These changes in capitalization may significantly increase our level of debt. If we incur additional debt for these or other purposes, the related risks that we now face could intensify. A higher level of debt also increases the risk that we may default on our debt obligations. Our ability to meet our debt obligations and to reduce our level of debt depends on our future performance which is affected by general economic conditions and financial, business and other factors, many of which are beyond our control.

Our operations expose us to significant costs and liabilities with respect to environmental and operational safety matters.

We may incur significant delays, costs and liabilities as a result of environmental, health and safety requirements applicable to our oil and natural gas exploration, development and production, and related saltwater disposal activities. These delays, costs and liabilities could arise under a wide range of federal, state and local laws and regulations relating to protection of the environment, health and safety, including regulations and enforcement policies that have tended to become increasingly strict over time. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, imposition of cleanup and site restoration costs and liens, and, in some instances, issuance of orders or injunctions limiting or requiring discontinuation of certain operations. In addition, claims for damages to persons or property, including natural resources, may result from the environmental, health and safety impacts of our operations.

Strict as well as joint and several liability for a variety of environmental costs may be imposed on us under certain environmental laws, which could cause us to become liable for the conduct of others or for consequences of our own actions that were in compliance with all applicable laws at the time those actions were taken. New laws, regulations or enforcement policies could be more stringent and impose unforeseen liabilities or significantly increase compliance costs. No assurance can be given that continued compliance with existing or future environmental laws and regulations will not result in a curtailment of production or processing activities or result in a material increase in the costs of production, development, exploration or processing operations. If we are not able to recover the resulting costs through insurance or increased revenues, our production, revenues and results of operations could be adversely affected.

Our producing properties are concentrated in the Permian Basin of Southeast New Mexico and West Texas, making us vulnerable to risks associated with operating in one major geographic area. In addition, we have a large amount of proved reserves attributable to a small number of producing horizons within this area.

Our producing properties are geographically concentrated in the Permian Basin of Southeast New Mexico and West Texas. At December 31, 2014, substantially all of our total estimated proved reserves were attributable to properties located in this area. As a result of this concentration, we may be disproportionately exposed to the impact of regional supply and demand factors, delays or interruptions of production from wells in this area caused by governmental regulation, processing or transportation capacity constraints, market limitations, severe weather events, water shortages or other drought related conditions or interruption of the processing or transportation of oil, natural gas or natural gas liquids.

In addition to the geographic concentration of our producing properties described above, at December 31, 2014, approximately: (i) 30.6 percent of our proved reserves were attributable to the Yeso formation, which includes both the Paddock and Blinebry intervals, underlying our oil and natural gas properties located in Southeast New Mexico; (ii) 26.6 percent of our proved reserves were attributable to the Bone Spring formation located in the Delaware Basin; and (iii) 20.5 percent of our proved reserves were attributable to the Wolfberry play in West Texas. This concentration of assets within a small number of producing horizons exposes us to additional risks, such as changes in field-wide rules and regulations that could cause us to permanently or temporarily shut-in all of our wells within a field.

We periodically evaluate our unproved oil and natural gas properties for impairment, and could be required to recognize noncash charges to earnings of future periods.

At December 31, 2014, we carried unproved property costs of $1.1 billion. GAAP requires periodic evaluation of these costs on a project-by-project basis in comparison to their estimated fair value. These evaluations will be affected by the results of exploration activities, intent of future exploration activities, commodity price circumstances, planned future sales or expiration of all or a portion of the leases, future drilling plans, contracts and permits appurtenant to such projects. Based on our evaluations, we may determine that we are unable to fully recover the cost invested in each project, and we will recognize noncash charges to earnings in future periods.

Part of our strategy involves exploratory drilling, including drilling in new or emerging plays. As a result, our drilling results in these areas are uncertain, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

The results of our exploratory drilling in new or emerging plays are more uncertain than drilling results in areas that are developed and have established production. Since new or emerging plays and new formations have limited or no production history, we are unable to use past drilling results in those areas to help predict our future drilling results. As a result, our cost of drilling, completing and operating wells in these areas may be higher than initially expected, and the value of our undeveloped acreage will decline if drilling results are unsuccessful.

Our commodity price risk management program may cause us to forego additional future profits or result in our making cash payments to our counterparties.

To reduce our exposure to changes in the prices of commodities, we have entered into and may in the future enter into additional commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Commodity price risk management arrangements expose us to the risk of financial loss and may limit our ability to benefit from increases in commodity prices in some circumstances, including the following:

- the counterparty to a commodity price risk management contract may default on its contractual obligations to us;

- there may be a change in the expected differential between the underlying price in a commodity price risk management agreement and actual prices received; or

- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments to our counterparties.

Our commodity price risk management activities could have the effect of reducing our net income and the value of our securities. At December 31, 2014, the Company had a net derivative asset of approximately $752.7 million. An average increase in the commodity price of $10.00 per barrel of oil and $1.00 per MMBtu for natural gas from the commodity price at December 31, 2014 would have resulted in a decrease in our net asset of approximately $268.8 million. We may continue to incur significant gains or losses in the future from our commodity price risk management activities to the extent market prices increase or decrease and our derivatives contracts remain in place.

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

We have identified and scheduled the drilling of certain of our drilling locations as an estimation of our future multi-year development activities on our existing acreage. These identified locations represent a significant part of our growth strategy. Our ability to drill and develop these locations depends on a number of uncertainties, including: (i) our ability to timely drill wells on lands subject to complex development terms and circumstances; (ii) the availability of capital, equipment, services and personnel; (iii) weather conditions; (iv) regulatory and third-party approvals; (v) commodity prices; (vi) access to and availability of water sourcing and distribution systems; and (vii) drilling and recompletion costs and results. Additionally, changes in the laws or regulations on which we rely in planning and executing our drilling programs could adversely impact our ability to successfully complete those programs. Because of these and other potential uncertainties, we may never drill the potential locations we have identified or produce oil or natural gas from these or any other potential locations. As such, our actual development activities may materially differ from those presently identified, which could adversely affect our production, revenues and results of operations.

Unless we replace our oil and natural gas reserves, our reserves and production will decline, which would adversely affect our cash flow, our ability to raise capital and the value of our securities.

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

The Standardized Measure and PV-10 of our estimated reserves are not accurate estimates of the current fair value of our estimated proved oil and natural gas reserves.

Standardized Measure is a reporting convention that provides a common basis for comparing oil and natural gas companies subject to the rules and regulations of the SEC. Our non-GAAP financial measure, PV-10, is a similar reporting convention that we have disclosed in this report. Both measures require the use of operating and development costs prevailing as of the date of computation. Consequently, they will not reflect the prices ordinarily received or that will be received for oil and natural gas production because of varying market conditions, nor may it reflect the actual costs that will be required to produce or develop the oil and natural gas properties. Accordingly, estimates included herein of future net cash flows may be materially different from the future net cash flows that are ultimately received. In addition, the 10 percent discount factor, which is required by the rules and regulations of the SEC to be used in calculating discounted future net cash flows for reporting purposes, may not be the most appropriate discount factor based on interest rates in effect from time to time and risks associated with our company or the oil and natural gas industry in general. Therefore, Standardized Measure or PV-10 included in this report should not be construed as accurate estimates of the current fair value of our proved reserves.

Our reserve estimates and our computation of future net cash flows are based on SEC pricing of (i) $91.48 per Bbl WTI posted oil price and (ii) $4.35 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property. The SEC pricing for reserves as of December 31, 2014 is higher than the NYMEX oil price and NYMEX natural gas price of $49.28 per Bbl and $2.90 per MMBtu, respectively, at February 24, 2015. If current pricing measures were used, estimates of our reserves and PV-10 would be lower. For example, if average oil prices were $10.00 per barrel lower than the average price we used, our PV-10 at December 31, 2014 would have decreased from $11.4 billion to $9.7 billion. If average natural gas prices were $1.00 per MMBtu lower than the average price we used, our PV-10 at December 31, 2014, would have decreased from $11.4 billion to $10.6 billion. Any adjustments to the estimates of proved reserves or decreases in the price of our commodities may decrease the value of our securities.

We may be unable to make attractive acquisitions or successfully integrate acquired companies or assets, and any inability to do so may disrupt our business and hinder our ability to grow.

One aspect of our business strategy calls for acquisitions of businesses or assets that complement or expand our current business. We may not be able to identify attractive acquisition opportunities. Even if we do identify attractive candidates, we may not be able to complete the acquisition of them or do so on commercially acceptable terms.

In addition, our credit facility and the indentures governing our senior notes impose certain limitations on our ability to enter into mergers or combination transactions. Our credit facility and the indentures governing our senior notes also limit our ability to incur certain indebtedness, which could indirectly limit our ability to engage in acquisitions of businesses or assets. If we desire to engage in an acquisition that is otherwise prohibited by our credit facility or the indentures governing our senior notes, we will be required to seek the consent of our lenders or the holders of the senior notes in accordance with the requirements of the credit facility or the indentures, which consent may be withheld by the lenders under our credit facility or such holders of senior notes at their sole discretion.

If we acquire another business or assets, we could have difficulty integrating its operations, systems, management and other personnel and technology with our own. These difficulties could disrupt our ongoing business, distract our management and employees, increase our expenses and adversely affect our results of operations. In addition, we may incur additional debt or issue additional equity to pay for any future acquisitions, subject to the limitations described above.

Any acquisition we complete is subject to substantial risks that could adversely affect our business, including the risk that our acquisitions may prove to be worth less than what we paid because of uncertainties in evaluating recoverable reserves and could expose us to potentially significant liabilities.

We obtained a significant portion of our current reserve base through acquisitions of producing properties and undeveloped acreage. We expect that acquisitions will continue to contribute to our future growth. In connection with these and potential future acquisitions, we are often only able to perform limited due diligence. The success of any acquisition involves potential risks, including among other things:

- the inability to estimate accurately the costs to develop the reserves, recoverable volumes of reserves, rates of future production and future net cash flows attainable from the reserves;

- the assumption of unknown liabilities, including environmental liabilities, and losses or costs for which the Company is not indemnified or for which the indemnity the Company receives is inadequate;

- the effect on our liquidity or financial leverage of using available cash or debt to finance acquisitions;
- the diversion of management's attention from other business concerns; and
- an inability to hire, train or retain qualified personnel to manage and operate our growing business and assets.

Successful acquisitions of oil and natural gas properties require an assessment of a number of factors, including estimates of recoverable reserves, the timing of recovering reserves, exploration potential, future commodity prices, operating costs and potential environmental, regulatory and other liabilities. Such assessments are inexact, and we cannot make these assessments with a high degree of accuracy. In connection with our assessments, we perform a review of the acquired properties that we believe to be generally consistent with industry practices. However, such a review will not reveal all existing or potential problems. In addition, our review may not permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well. Even when we inspect a well, we do not always discover structural, subsurface and environmental problems that may exist or arise.

There may be threatened, contemplated, asserted or other claims against the acquired assets related to environmental, title, regulatory, tax, contract, litigation or other matters of which we are unaware, which could materially and adversely affect our production, revenues and results of operations. We are sometimes able to obtain contractual indemnification for preclosing liabilities, including environmental liabilities, but we generally acquire interests in properties on an “as is” basis with limited remedies for breaches of representations and warranties. In addition, even when we are able to obtain such indemnification from the sellers, these indemnification obligations usually expire over time and expose us to potential unindemnified liabilities, which could materially adversely affect our production, revenues and results of operations.

Shortages of oilfield equipment, services and qualified personnel could delay our drilling program and increase the prices we pay to obtain such equipment, services and personnel.

The demand for qualified and experienced field personnel to drill wells and conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with commodity prices, causing periodic shortages. Historically, there have been shortages of drilling and workover rigs, pipe and other oilfield equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher commodity prices generally stimulate demand and result in increased prices for drilling and workover rigs, crews and associated supplies, equipment and services. It is beyond our control and ability to predict whether these conditions will exist in the future and, if so, what their timing and duration will be. These types of shortages or price increases could significantly decrease our profit margin, cash flow and operating results, or restrict our ability to drill the wells and conduct the operations which we currently have planned and budgeted or which we may plan in the future.

Our exploration and development drilling may not result in commercially productive reserves.

Drilling activities are subject to many risks, including the risk that commercially productive reservoirs will not be encountered. New wells that we drill may not be productive, or we may not recover all or any portion of our investment in such wells. The seismic data and other technologies we use do not allow us to know conclusively prior to drilling a well that oil or natural gas is present or may be produced economically. Drilling for oil and natural gas often involves unprofitable results, not only from dry holes but also from wells that are productive but do not produce sufficient net reserves to return a profit at then realized prices after deducting drilling, operating and other costs. The cost of drilling, completing and operating a well is often uncertain, and cost factors can adversely affect the economics of a project. Further, our drilling operations may be curtailed, delayed or canceled as a result of numerous factors, including:

- unexpected drilling conditions;
- title problems;
- pressure or irregularities in formations;
- equipment failures or accidents;

- fracture stimulation accidents or failures;

- adverse weather conditions;

- compliance with environmental and other governmental or contractual requirements; and

- increases in the cost of, or shortages or delays in the availability of, electricity, water, supplies, materials, drilling or workover rigs, equipment and services.

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

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

- environmental hazards, such as uncontrollable flows of oil, natural gas, brine, well fluids, toxic gas or other pollution into the environment, including groundwater contamination;

- abnormally pressured or structured formations;

- mechanical difficulties, such as stuck oilfield drilling and service tools and casing collapse;

- blowouts, cratering, fires, explosions and ruptures of pipelines;

- personal injuries and death; and
- natural disasters.

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

- injury or loss of life;
- damage to and destruction of property and equipment;
- damage to natural resources due to underground migration of hydraulic fracturing fluids;
- pollution and other environmental damage, including spillage or mishandling of recovered hydraulic fracturing fluids;
- regulatory investigations and penalties;
- suspension of our operations; and
- repair and remediation costs.

We may elect not to obtain insurance if we believe that the cost of available insurance is excessive relative to the risks presented. In addition, pollution and environmental risks generally are not fully insurable. The occurrence of an event that is not covered or not fully covered by insurance could have a material adverse effect on our production, revenues and results of operations.

Competition in the oil and natural gas industry is intense, making it more difficult for us to acquire properties, market oil and natural gas and secure trained personnel.

We operate in a highly competitive environment for acquiring properties, marketing oil and natural gas and securing trained personnel. Some of our competitors possess and employ financial, technical and personnel resources substantially greater than ours, which can be particularly important in the areas in which we operate. Those companies may be able to pay more for productive oil and natural gas properties and exploratory prospects and to evaluate, bid for and purchase a greater number of properties and prospects than our financial or personnel resources permit. In addition, those companies may be able to offer better compensation packages to attract and retain qualified personnel than we are able to offer. The cost to attract and retain qualified personnel has increased over the past few years due to competition and may increase substantially in the future. Our ability to acquire additional prospects and to find and develop reserves in the future will depend on our ability to evaluate and select suitable properties and to consummate transactions in a highly competitive environment. Also, there is substantial competition for capital available for investment in the oil and natural gas industry. We may not be able to compete successfully in the future in acquiring prospective reserves, developing reserves, marketing hydrocarbons, attracting and retaining quality personnel and raising additional capital. Our failure to acquire properties, market oil and natural gas and secure trained personnel and adequately compensate personnel could have a material adverse effect on our production, revenues and results of operations.

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 processing or transportation arrangements may hinder our access to oil, natural gas and natural gas liquid 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, natural gas and natural gas liquids, the proximity of reserves to pipelines and terminal facilities, competition for such facilities and the inability of such facilities to gather, transport or process our production due to shutdowns or curtailments arising from mechanical, operational or weather related matters, including hurricanes and other severe weather conditions. Our ability to market our production depends in substantial part on the availability and capacity of gathering and transportation systems, pipelines and processing facilities owned and operated by third parties. Our failure to obtain such services on acceptable terms could have a material adverse effect on our business, financial condition and results of operations. We may be required to shut in or otherwise curtail production from wells due to lack of a market or inadequacy or unavailability of oil, natural gas liquid or natural gas pipeline or gathering, transportation or processing capacity. If that were to occur, then we would be unable to realize revenue from those wells until suitable arrangements were made to market our production.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, timing, manner or feasibility of conducting our operations or that may subject us to fines or penalties for any failure to comply.

Our oil and natural gas exploration, development and production, and related saltwater disposal operations are subject to complex and stringent laws and regulations. In order to conduct our operations in compliance with these laws and regulations, we must obtain and maintain numerous permits, approvals and certificates from various federal, state, local and governmental authorities. We may incur substantial costs and experience delays in order to maintain compliance with these existing laws and regulations. If we fail to comply with the existing laws and regulations, we may incur additional costs, including fines and penalties, in order to come back into compliance. In addition, our costs of compliance may increase or our operations may be otherwise adversely affected if existing laws and regulations are revised or reinterpreted or if the government agencies responsible for enforcing certain existing laws and regulations applicable to us change their priorities or policies, or if new laws and regulations become applicable to our operations. These and other costs could have a material adverse effect on our production, revenues and results of operations.

Certain federal income tax deductions currently available with respect to oil and natural gas exploration and development may be eliminated as a result of future legislation.

President Obama’s budget proposal for the fiscal year 2016 recommends the elimination of certain key United States federal income tax preferences currently available to oil and natural gas exploration and production companies and legislation has been introduced in Congress that would implement many of these proposals. These changes include, but are not limited to, (i) the repeal of the percentage depletion allowance for oil and natural gas properties, (ii) the elimination of current deductions for intangible drilling and development costs, (iii) the elimination of the deduction for certain domestic production activities and (iv) the increase in the amortization period from two years to seven years for geophysical costs paid or incurred by independent producers in connection with the exploration for, or development of, oil or natural gas within the United States.

It is unclear whether any such changes will actually be enacted or, if enacted, how soon any such changes could become effective. The passage of any legislation as a result of the budget proposal, tax reform efforts, or any other similar change in United States federal income tax law could affect certain tax deductions that are currently available to us with respect to our oil and natural gas exploration and production activities.

Climate change legislation or regulations restricting emissions of “greenhouse gases” could result in increased operating costs and reduced demand for the crude oil and natural gas that we produce.

In December 2009, the EPA determined that emissions of carbon dioxide, methane and other GHGs present an endangerment to public health and the environment because emissions of such gases are, according to the EPA, contributing to warming of the earth's atmosphere and other climatic changes. Based on these findings, the EPA has begun adopting and implementing regulations to restrict emissions of GHGs under existing provisions of the CAA. The EPA recently adopted two sets of rules regulating GHG emissions under the CAA, one of which requires a reduction in emissions of GHGs from motor vehicles and the other of which regulates emissions of GHGs from certain large stationary sources. The EPA's rules relating to emissions of GHGs, including emissions, from large stationary sources are currently subject to a number of legal challenges, but the federal courts have thus far declined to issue any injunctions to prevent the EPA from implementing, or requiring state environmental agencies to implement, the rules. The EPA has also adopted rules requiring the reporting of GHG emissions from specified large GHG emission sources in the United States, including certain onshore oil and natural gas production facilities, on an annual basis.

While Congress has from time to time considered legislation to reduce emissions of GHGs, there has not been significant activity in the form of adopted legislation to reduce emissions of GHGs in recent years. In the absence of Congressional action, almost one-half of the states have taken legal measures to reduce emissions of GHGs primarily through the planned development of GHG emission inventories and/or regional GHG cap and trade programs. Most of these cap and trade programs work by requiring major sources of emissions, such as electric power plants, or major producers of fuels, such as refineries and natural gas processing plants, to acquire and surrender emission allowances. The number of allowances available for purchase is reduced each year in an effort to achieve the overall GHG emission reduction goal.

The adoption of legislation or regulatory programs to reduce emissions of GHGs could require us to incur increased operating costs, such as costs to purchase and operate emissions control systems, to acquire emissions allowances or to comply with new regulatory or reporting requirements. For example, pursuant to President Obama's Strategy to Reduce Methane Emissions, the Obama Administration announced on January 14, 2015, that the EPA is expected to propose in the summer of 2015 and finalize in 2016 new regulations that will set methane emission standards for new and modified oil and gas production and natural gas processing and transmission facilities as part of the Administration's efforts to reduce methane emissions from the oil and gas sector by up to 45 percent from 2012 levels by 2025. Any such legislation or regulatory programs could also increase the cost of consuming, and thereby reduce demand for, the oil and natural gas we produced. Consequently, legislation and regulatory programs to reduce emissions of GHGs could have an adverse effect on our business, financial condition and results of operations. Finally, it should be noted that some scientists have concluded that increasing concentrations of GHGs in the earth's atmosphere may produce climate changes that have significant physical effects, such as increased frequency and severity of storms, droughts, and floods and other climatic events. If any such effects were to occur, they could have an adverse effect on our financial condition and results of operations.

The adoption of derivatives legislation by Congress 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.

Congress adopted comprehensive financial reform legislation that establishes federal oversight and regulation of the over-the-counter derivatives market and entities, including us, which participate in that market. This legislation, known as the Dodd-Frank Wall Street Reform and Consumer Protection Act (the "Act"), became law on July 21, 2010 and requires the Commodities Futures Trading Commission (the "CFTC") and the SEC to promulgate rules and regulations implementing the Act. Although the CFTC has finalized certain regulations, others remain to be finalized or implemented and it is not possible at this time to predict when this will be accomplished. In October 2011, the CFTC issued regulations to set position limits for certain futures and option contracts in the major energy markets and for swaps that are their economic equivalents. The initial position limits rule was vacated by the United States District Court for the District of Columbia in September 2012. However, in November 2013, the CFTC proposed new rules that would place limits on positions in certain core futures and equivalent swaps contracts for or linked to certain physical commodities, subject to exceptions for certain bona fide hedging transactions. As these new position limit rules are not yet final, the impact of those provisions on us is uncertain at this time. The CFTC has designated certain interest rate swaps and credit default swaps for mandatory clearing and the associated rules also will require us, in connection with covered derivative activities, to comply with clearing and trade-execution requirements or take steps to qualify for an exemption to such requirements. Although we expect to qualify for the end-user exception from the mandatory clearing requirements for swaps entered to hedge our commercial risks, the application of the mandatory clearing and trade execution requirements to other market participants, such as swap dealers, may change the cost and availability of the swaps that we use for hedging. In addition, for uncleared swaps, the CFTC or federal banking regulators may require end-users to enter into credit support documentation and/or post initial and variation margin. Posting of collateral could impact liquidity and reduce cash available to us for capital expenditures, therefore reducing our ability to execute hedges to reduce risk and protect cash flows. The proposed margin rules are not yet final, and therefore the impact of those provisions is uncertain at this time. The Act also may require the counterparties to our derivative instruments to spin off some of their derivatives activities to a separate entity, which may not be as creditworthy as the current counterparty.

The full impact of the Act and related regulatory requirements upon our business will not be known until the regulations are implemented and the market for derivatives contracts has adjusted. The Act and any new regulations could significantly increase the cost of derivative contracts, materially alter the terms of derivative contracts, reduce the availability of derivatives to protect against risks we encounter, reduce our ability to monetize or restructure our existing derivative contracts or increase our exposure to less creditworthy counterparties. If we reduce our use of derivatives as a result of the Act and regulations implementing the Act, 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. Finally, the Act was intended, in part, to reduce the volatility of commodity prices, which some legislators attributed to speculative trading in derivatives and commodity instruments related to oil and natural gas. Our revenues could therefore be adversely affected if a consequence of the Act and implementing regulations is to lower commodity prices. Any of these consequences could have a material adverse effect on us, our financial condition and our results of operations.

The loss of our chief executive officer or other key personnel could negatively impact our ability to execute our business strategy.

We depend, and will continue to depend in the foreseeable future, on the services of our chief executive officer, Timothy A. Leach, and other officers and key employees who have extensive experience and expertise in evaluating and analyzing producing oil and natural gas properties and drilling prospects, maximizing production from oil and natural gas properties, marketing oil and natural gas production, and developing and executing acquisition, financing and hedging strategies. Our ability to hire and retain our officers and key employees is important to our continued success and growth. The unexpected loss of the services of one or more of these individuals could negatively impact our ability to execute our business strategy.

Because we do not operate and therefore control the development of certain of the properties in which we own interests, we may not be able to produce economic quantities of oil and natural gas in a timely manner.

At December 31, 2014, approximately 8.5 percent of our proved reserves were attributable to properties for which we were not the operator. As a result, the success and timing of drilling and development activities on such nonoperated properties depend upon a number of factors, including:

- the nature and timing of drilling and operational activities;
- the timing and amount of capital expenditures;
- the operators’ expertise and financial resources;
- the approval of other participants in such properties; and
- the selection and application of suitable technology.

If drilling and development activities are not conducted on these properties or are not conducted on a timely basis, we may be unable to increase our production or offset normal production declines or we will be required to write-off the reserves attributable thereto, which may adversely affect our production, revenues and results of operations. Any such write-offs of our reserves could reduce our ability to borrow money and could reduce the value of our securities

Uncertainties associated with enhanced recovery methods may result in us not realizing an acceptable return on our investments in such projects.

We inject water into formations on some of our properties to increase the production of oil and natural gas. We may in the future expand these efforts to more of our properties or employ other enhanced recovery methods in our operations. The additional production and reserves, if any, attributable to the use of enhanced recovery methods are inherently difficult to predict. If our enhanced recovery methods do not allow for the extraction of oil and natural gas in a manner or to the extent that we anticipate, we may not realize an acceptable return on our investments in such projects.

Part of our strategy involves using some of the latest available horizontal drilling and completion techniques, which involve risks and uncertainties in their application.

Our operations involve utilizing some of the latest drilling and completion techniques. Risks that we face while drilling horizontal wells include, but are not limited to, the following:

- landing the wellbore in the desired drilling zone;
- staying in the desired drilling zone while drilling horizontally through the formation;
- running casing the entire length of the wellbore; and
- being able to run tools and other equipment consistently through the horizontal wellbore.

Risks that we face while completing wells include, but are not limited to, the following:

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- the ability to fracture stimulate the planned number of stages;
- the ability to run tools the entire length of the wellbore during completion operations; and
- the ability to successfully clean out the wellbore after completion of the final fracture stimulation stage.

A terrorist or cyber-attack or armed conflict could harm our business by decreasing our revenues and increasing our costs.

Terrorist activities, anti-terrorist efforts, cyber-attacks and other armed conflict involving the United States may adversely affect the United States and global economies and could prevent us from meeting our financial and other obligations. If any of these events occur or escalate, the resulting political instability and societal disruption could reduce overall demand for oil and natural gas, potentially putting downward pressure on demand for our production and causing a reduction in our revenue. Oil and natural gas related facilities could be direct targets of terrorist attacks, and our operations could be adversely impacted if significant infrastructure or facilities used for the production, transportation, processing or marketing of oil and natural gas production are destroyed or damaged. Additionally, as an oil and natural gas producer, we may face various cybersecurity threats, including threats to gain unauthorized access to sensitive information or to render data or systems unusable, and there can be no assurance that our implementation of various procedures and controls to monitor and mitigate security threats will be sufficient to prevent security breaches from occurring. Costs for insurance and other security may increase as a result of these threats, and some insurance coverage may become more difficult to obtain, if available at all.

Cybersecurity breaches and information technology failures could harm our business by increasing our costs and negatively impacting our operations.

We rely extensively on information technology systems, including Internet sites, data hosting facilities and other hardware and platforms, some of which are hosted by third parties, to assist in conducting our business. Our information technology systems, as well as those of third parties we use in our operations, may be vulnerable to a variety of cybersecurity risks, such as those involving unauthorized access, malicious software, data privacy breaches by employees or others with authorized access, cyber or phishing-attacks and other security issues.

Although we have implemented information technology controls and systems that are designed to protect information and prevent or minimize the risk of data loss and other cybersecurity risks, such measures cannot entirely eliminate cybersecurity threats, and the enhanced controls we have installed may be breached or may fail. If our information technology systems cease to function properly or our cybersecurity is breached, we could suffer disruptions to our operations and unauthorized persons may gain access to proprietary or confidential information, which could result in loss or disclosure of, or damage to, our or any of our customer’s or supplier’s data or confidential information; misuse or misappropriation of data, funds or other property; and other manipulation or improper use of our systems or networks. This could harm our business by damaging our reputation, subjecting us to potential financial or legal liability, and requiring us to incur significant costs, including costs to repair or restore the security of our internal systems or to take other remedial steps.

Risks Related to Our Common Stock

Our restated certificate of incorporation, our bylaws and Delaware law contain provisions that could discourage acquisition bids or merger proposals, which may adversely affect the market price of our common stock.

Our restated certificate of incorporation authorizes our board of directors to issue preferred stock without stockholder approval. If our board of directors elects to issue preferred stock, it could be more difficult for a third party to acquire us. In addition, some provisions of our certificate of incorporation, our bylaws and Delaware law could make it more difficult for a third party to acquire control of us, even if the change of control would be beneficial to our stockholders, including:

- the organization of our board of directors as a classified board, which allows no more than approximately one-third of our directors to be elected each year;

- stockholders cannot remove directors from our board of directors except for cause and then only by the holders of not less than 66 2/3 percent of the voting power of all outstanding voting stock;

- the prohibition of stockholder action by written consent; and

- limitations on the ability of our stockholders to call special meetings and establish advance notice provisions for stockholder proposals and nominations for elections to the board of directors to be acted upon at meetings of stockholders.

Because we have no plans to pay dividends on our common stock, investors must look solely to stock appreciation for a return on their investment in us.

We do not anticipate paying any cash dividends on our common stock in the foreseeable future. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. Covenants contained in our credit facility and the indentures governing our senior notes restrict the payment of dividends. Investors must rely on sales of their common stock after price appreciation, which may never occur, as the only way to realize a return on their investment.

Investors seeking cash dividends should not purchase our common stock.

The availability of shares for sale in the future could reduce the market price of our common stock.

In the future, we may issue securities to raise cash for acquisitions. We may also acquire interests in other companies by using a combination of cash and our common stock or just our common stock. We may also issue securities convertible into, or exchangeable for, or that represent the right to receive, our common stock. Any of these events may dilute your ownership interest in our company, reduce our earnings per share and have an adverse impact on the price of our common stock.

In addition, sales of a substantial amount of our common stock in the public market, or the perception that these sales may occur, could reduce the market price of our common stock. This could also impair our ability to raise additional capital through the sale of our securities.

The market price and trading volume of our common stock may be volatile, which could result in losses for our stockholders.

The market price of our common stock may be volatile and could be subject to wide fluctuations. In addition, the trading volume of our common stock may fluctuate and cause price variations to occur. The market price of our common stock may fluctuate or decline significantly in the future. If the market price of our common stock declines, you may be unable to sell your shares of common stock at or above your purchase price. Some of the factors that could negatively affect the price of our common stock, or result in fluctuations in the price or trading volume of our common stock, include:

- fluctuations in the price of oil or natural gas;

- variations in our quarterly operating results or failure to meet analysts' earnings expectations;

- publication of negative research reports about us or the oil and natural gas industry or adverse publicity about the oil and natural gas industry;
- adverse market reaction to any indebtedness we may incur or securities we may issue in the future or actions by our stockholders;
- sales of a large number of our common stock or the perception that such sales could occur;
- changes in market valuations of similar companies;
- the effects of government regulation, permitting and other legal requirements, including new legislation or regulation of hydraulic fracturing and the export of oil and natural gas;
- litigation and governmental investigations; and
- general economic and business conditions, either internationally or domestically.

Item 1B. Unresolved Staff Comments

There are no unresolved staff comments.

Item 2. Properties

Our Oil and Natural Gas Reserves

The estimates of our proved reserves at December 31, 2014, all of which were located in the United States, were based on evaluations prepared by the independent petroleum engineering firms of Cawley, Gillespie & Associates, Inc. ("CGA") and Netherland, Sewell & Associates, Inc. ("NSAI") (collectively, our "external engineers"). Reserves were estimated in accordance with guidelines established by the SEC and the Financial Accounting Standards Board (the "FASB").

Internal controls. Our proved reserves are estimated at the property level and compiled for reporting purposes by our corporate reservoir engineering staff, all of whom are independent of our operating teams. We maintain our internal evaluations of our reserves in a secure reserve engineering database. The corporate reservoir engineering staff interact with our internal staff of petroleum engineers and geoscience professionals in each of our operating areas and with accounting and marketing employees to obtain the necessary data for the reserves estimation process. Reserves are reviewed and approved internally by members of our senior management and the reserves committee.

Our internal professional staff works closely with our external engineers to ensure the integrity, accuracy and timeliness of data that is furnished to them for their reserve estimation process. All of the reserve information maintained in our secure reserve engineering database is provided to the external engineers. In addition, other pertinent data is provided such as seismic information, geologic maps, well logs, production tests, material balance calculations, well performance data, operating procedures and relevant economic criteria. We make available all information requested, including our pertinent personnel, to the external engineers as part of their preparation of our reserves.

Qualifications of responsible technical persons

J. Steve Guthrie has been our Senior Vice President of Business Operations and Engineering since November 2013. Mr. Guthrie previously served as the Vice President of Texas from October 2010 to November 2013. Mr. Guthrie also served as Texas Asset Manager from July 2008 to October 2010 and as Corporate Engineering Manager from August 2004 to July 2008. Prior to joining the Company in 2004, Mr. Guthrie was employed by Moriah Resources as Business Development Manager, by Henry Petroleum in various engineering and operations capacities and by Exxon in several engineering and operations positions. Mr. Guthrie is a graduate of Texas Tech University with a Bachelor of Science degree in Petroleum Engineering.

Rick Morton joined the Company in 2011 as Corporate Engineering Manager. Prior to joining the Company, Mr. Morton served as Division Acquisition Coordinator for EOG Resources, Inc. Mr. Morton was also previously employed by Southwest Royalties, Inc. as Vice President and Exploitation Manager, and by Merit Energy Company in various engineering positions. Mr. Morton began his career in 1983 with Arco Oil and Gas Company as an Operations/Analytical Engineer before moving to a Production Supervisor position. He is a graduate of Texas A&M University with a Bachelor of Science degree in Petroleum Engineering.

CGA. Approximately 69 percent of the proved reserves estimates shown herein at December 31, 2014 have been independently prepared by CGA, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. CGA was founded in 1960 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-693. Within CGA, the technical person primarily responsible for preparing the estimates set forth in the CGA letter dated January 15, 2015, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Zane Meekins. Mr. Meekins has been a practicing consulting petroleum engineer at CGA since 1989. Mr. Meekins is a Registered Professional Engineer in the State of Texas (License No. 71055) and has over 24 years of practical experience in petroleum engineering, with over 20 years of experience in the estimation and evaluation of reserves. He graduated from Texas A&M University in 1987 with a Bachelor of Science degree in Petroleum Engineering. Mr. Meekins meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

NSAI. Approximately 31 percent of the proved reserve estimates shown herein at December 31, 2014 have been independently prepared by NSAI, a worldwide leader of petroleum property analysis for industry and financial organizations and government agencies. NSAI was founded in 1961 and performs consulting petroleum engineering services under Texas Board of Professional Engineers Registration No. F-2699. Within NSAI, the technical person primarily responsible for preparing the estimates set forth in the NSAI letter dated January 20, 2015, filed as an exhibit to this Annual Report on Form 10-K, was Mr. Michael Begland. Mr. Begland, a Licensed Professional Engineer in the State of Texas (License No. 104898), has been practicing consulting petroleum engineering at NSAI since 1993 and has over seven years of prior industry experience. He graduated from Ohio State University in 1983 with a Bachelor of Science Degree in Chemical Engineering. Mr. Begland meets or exceeds the education, training, and experience requirements set forth in the Standards Pertaining to the Estimating and Auditing of Oil and Gas Reserves Information promulgated by the Society of Petroleum Engineers; he is proficient in judiciously applying industry standard practices to engineering and geoscience evaluations as well as applying SEC and other industry reserve definitions and guidelines.

Our oil and natural gas reserves. The following table sets forth our estimated proved oil and natural gas reserves, PV-10 and Standardized Measure at December 31, 2014. PV-10 and Standardized Measure include the present value of our estimated future abandonment and site restoration costs for proved properties net of the present value of estimated salvage proceeds from each of these properties. Our reserve estimates and our computation of future net cash flows are based on SEC pricing of (i) $91.48 per Bbl WTI posted oil price and (ii) $4.35 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property.

	Oil	**Natural Gas**	**Total**	**PV-10 (b)**
	(MBbl)	**(MMcf)**	**(MBoe)**	**(in millions)**

Core Operating Areas:				
New Mexico Shelf	140,756	642,359	247,816	$ 4,315.2
Delaware Basin	139,768	624,481	243,848	4,878.8
Texas Permian	89,816	333,580	145,413	2,189.6
Other	7	595	106	1.2
Total	370,347	1,601,015	637,183	11,384.8
Present value of future income taxes discounted at 10%				(3,362.0)
Standardized Measure				$ 8,022.8

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The following table sets forth our estimated proved reserves by category at December 31, 2014:

	Oil (MBbl)	Natural Gas (MMcf)	Total (MBoe) (a)	Percent of Total	PV-10 (b) (in millions)
Proved developed producing	194,643	945,029	352,148	55.2%	$ 7,928.6
Proved developed non-producing	16,803	47,538	24,726	3.9%	400.9
Proved undeveloped	158,901	608,448	260,309	40.9%	3,055.3
Total proved	370,347	1,601,015	637,183	100.0%	$ 11,384.8
Total proved developed	211,446	992,567	376,874	59.1%	$ 8,329.5

(a) One barrel of oil equivalent is equal to six Mcf of natural gas or one Bbl of oil, as determined under the relative energy content method.

(b) Our Standardized Measure at December 31, 2014 was $8.0 billion. PV-10 is a Non-GAAP financial measure and is derived from the Standardized Measure which is the most directly comparable GAAP financial measure. PV-10 is a computation of the Standardized Measure on a pre-tax basis. PV-10 is equal to the Standardized Measure at the applicable date, before deducting future income taxes, discounted at 10 percent. We believe that the presentation of PV-10 is relevant and useful to investors because it presents the discounted future net cash flows attributable to our estimated proved reserves prior to taking into account future corporate income taxes, and it is a useful measure for evaluating the relative monetary significance of our oil and natural gas assets. Further, investors may utilize the measure as a basis for comparison of the relative size and value of our reserves to other companies. We use this measure when assessing the potential return on investment related to our oil and natural gas assets. PV-10, however, is not a substitute for the Standardized Measure. Our PV-10 measure and the Standardized Measure do not purport to present the fair value of our oil and natural gas reserves. See “Item 1. Business —Non-GAAP Financial Measures and Reconciliations.”

Changes to proved reserves. The following table sets forth the changes in our proved reserve volumes by area during the year ended December 31, 2014 (in MBoe):

	Production	Extensions and Discoveries	Purchases of Minerals-in-Place	Revisions of Previous Estimates
Core Operating Areas:				
New Mexico Shelf	(11,524)	43,392	-	(9,586)
Delaware Basin	(20,674)	95,104	5,671	25,668

Texas Permian	(8,664)	43,615	34	(28,770)
Other	(13)	-	-	9
Total	(40,875)	182,111	5,705	(12,679)

Extensions and discoveries. Extensions and discoveries of approximately 182.1 MMBoe are primarily the result of our continued success from our extension and infill horizontal drilling programs in our core operating areas. There were approximately 61.3 MMBoe of proved developed reserves that were directly added through our drilling activity last year. Based upon this activity, approximately 120.8 MMBoe of new proved undeveloped locations were added, of which, approximately 73.2 MMBoe of proved undeveloped reserves were one offset location from an existing producing well. In addition, within some of our core operating areas, one or more reliable technologies supported additional proved undeveloped locations that are more than one offset away from a producing well. There were approximately 300 such proved undeveloped locations added based on reliable technology. These locations resulted in 47.6 MMBoe of net proved reserves.

Purchases of minerals-in-place. Our purchases of minerals-in-place are composed of approximately 5.7 MMBoe from various acquisitions throughout the year.

Revisions of previous estimates. Revisions of previous estimates are comprised of (i) 36.2 MMBoe of proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within the five years of their initial recording required by SEC rules, (ii) a 23.6 MMBoe net positive revision resulting from both positive and negative technical and performance evaluations and (iii) 0.1 MMBoe of negative price revisions. Our proved reserves at December 31, 2014 were determined using the SEC prices of $91.48 per Bbl of oil for WTI and $4.35 per MMBtu of natural gas for Henry Hub spot, compared to corresponding prices of $93.42 per Bbl of oil and $3.67 per MMBtu of natural gas at December 31, 2013.

Proved undeveloped reserves. At December 31, 2014, we had approximately 260.3 MMBoe of proved undeveloped reserves as compared to 199.7 MMBoe at December 31, 2013.

The following table summarizes the changes in our proved undeveloped reserves during 2014 (in MBoe):

At December 31, 2013	199,666
Extensions and discoveries	120,773
Purchases of minerals-in-place	708
Revisions of previous estimates	(27,324)
Conversion to proved developed reserves	(33,514)
At December 31, 2014	260,309

Extensions and discoveries of approximately 120.8 MMBoe are primarily the result of our continued success from our extension and infill horizontal drilling programs in our core operating areas. In addition, within some of our core operating areas, one or more reliable technologies supported additional proved undeveloped locations that are more than one offset away from a producing well. There were approximately 300 such proved undeveloped locations added based on reliable technology. These locations resulted in an additional 47.6 MMBoe of net proved reserves.

Our purchases of minerals-in-place are composed of approximately 0.7 MMBoe from various acquisitions throughout the year. Net negative revisions of previous estimates of approximately 27.3 MMBoe are primarily attributable to the reclassification of 36.2 MMBoe of proved undeveloped reserves because they are no longer expected to be developed within the five years of their initial recording primarily due to our transition to a horizontal drilling program as required by SEC rules, partially offset by 8.9 MMBoe of net positive revisions due to technical and performance evaluations.

The following table sets forth proved undeveloped reserves converted to proved developed reserves during the respective year and the investment required to convert proved undeveloped reserves to proved developed reserves:

Years Ended December 31,	**Proved Undeveloped Reserves Converted to Proved Developed Reserves**			**Investment in Conversion of Proved Undeveloped Reserves to Proved Developed Reserves**	
	Oil (MBbls)	**Natural Gas (MMcf)**	**Total (MBoe)**		**(in thousands)**
2010	20,117	52,318	28,836	$	309,439
2011	25,201	68,495	36,616		491,602
2012	19,132	60,388	29,196		411,576
2013	17,050	52,237	25,756		441,998

2014	20,970	75,266	33,514		561,198
Total	102,470	308,704	153,918	$	2,215,813

The following table sets forth the estimated timing and cash flows of developing our proved undeveloped reserves at December 31, 2014 (dollars in thousands):

Years Ended December 31, (a)	Future Production (MBoe)		Future Cash Inflows (b)		Future Production Costs		Future Development Costs		Future Net Cash Flows
2015	7,169	$	524,549	$	(56,212)	$	(1,010,302)	$	(541,965)
2016	17,725		1,288,784		(145,248)		(1,491,504)		(347,968)
2017	22,729		1,587,844		(193,848)		(788,598)		605,398
2018	20,182		1,382,074		(186,295)		(571,875)		623,904
2019	18,516		1,257,141		(183,101)		(351,472)		722,568
Thereafter	173,988		11,458,266		(3,133,393)		(31,329)		8,293,544
Total	260,309	$	17,498,658	$	(3,898,097)	$	(4,245,080)	$	9,355,481

(a) Beginning in 2015 and thereafter, the production and cash flows represent the drilling results from the respective year plus the incremental effects from the results of proved undeveloped drilling from previous years.

(b) Computation is based on SEC pricing of (i) $91.48 per Bbl WTI posted oil price and (ii) $4.35 per MMBtu Henry Hub spot natural gas price, adjusted for location and quality by property.

Historically, our drilling programs were substantially funded from our cash flow and borrowings from our credit facility and were weighted towards drilling unproven locations. Based on our current expectations over the next 5 years of our cash flows and drilling programs, which includes drilling of proved undeveloped and unproven locations, we believe that we can continue to substantially fund our drilling activities from our cash flow and with borrowings from our credit facility.

Developed and Undeveloped Acreage

The following table presents our total gross and net developed and undeveloped acreage by area at December 31, 2014:

	Developed Acres		Undeveloped Acres		Total Acres	
	Gross	Net	Gross	Net	Gross	Net
Core Operating Areas:						

New Mexico Shelf	130,246	87,850	27,580	18,709	157,826	106,559
Delaware Basin	369,229	236,592	267,013	187,293	636,242	423,885
Texas Permian	306,307	152,655	22,700	10,359	329,007	163,014
Other	3,135	1,912	981	981	4,116	2,893
Total	808,917	479,009	318,274	217,342	1,127,191	696,351

The following table sets forth the future expiration amounts of our gross and net undeveloped acreage at December 31, 2014 by area. Expirations may be less if production is established or continuous development activities are undertaken beyond the primary term of the lease.

	2015 (a)		**2016**		**2017**		**Thereafter**	
	Gross	**Net**	**Gross**	**Net**	**Gross**	**Net**	**Gross**	**Net**
Core Operating Areas:								
New Mexico Shelf	4,823	2,158	21,856	18,825	4,507	2,275	999	914
Delaware Basin	67,178	49,841	102,570	79,413	12,900	6,417	15,894	12,411
Texas Permian	23,425	10,411	1,044	811	2,079	736	186	31
Other	-	-	981	981	-	-	-	-
Total (b)	95,426	62,410	126,451	100,030	19,486	9,428	17,079	13,356

(a) Our 2015 capital budget contemplates avoiding a significant portion of these lease expirations.

(b) The total includes 103,014 gross (89,012 net) acres primarily in the outer limits of our southern Delaware Basin core area, most of which is expiring in 2016 and that we have no current plans to explore.

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Drilling Activities

For summary tables that set forth information with respect to wells drilled and completed for the years ended December 31, 2014, 2013 and 2012, see “Item 1. Business —Drilling Activities.”

Our Production, Prices and Expenses

For a summary table that sets forth information concerning our production and operating data from continuing operations for the years ended December 31, 2014, 2013 and 2012, see “Item 1. Business —Our Production, Prices and Expenses.”

Productive Wells

For a summary table that sets forth the number of productive oil and natural gas wells on our properties at December 31, 2014, 2013 and 2012, see “Item 1. Business —Productive Wells.”

Title to Our Properties

As is customary in the oil and natural gas industry, we initially conduct only a cursory review of the title to our properties on which we do not have proved reserves. Prior to the commencement of drilling operations on those properties, we conduct a more thorough title examination and perform curative work with respect to significant defects. To the extent title opinions or other investigations reflect defects affecting those properties, we are typically responsible for curing any such defects at our expense. We generally will not commence drilling operations on a property until we have cured known material title defects on such property. We have reviewed the title to substantially all of our producing properties and believe that we have satisfactory title to our producing properties in accordance with standards generally accepted in the oil and natural gas industry. Prior to completing an acquisition of producing oil and natural gas properties, we perform title reviews on the most significant properties and, depending on the materiality of properties, we may obtain a title opinion or review or update previously obtained title opinions. Our oil and natural gas properties are subject to customary royalty and other interests, liens to secure borrowings under our credit facility, liens for current taxes and other burdens which we believe do not materially interfere with the use or affect our carrying value of the properties.

Item 3. Legal Proceedings

We are a party to proceedings and claims incidental to our business. While many of these other matters involve inherent uncertainty, we believe that the liability, if any, ultimately incurred with respect to such other proceedings and claims will not have a material adverse effect on our consolidated financial position as a whole or on our liquidity, capital resources or future results of operations. We will continue to evaluate proceedings and claims involving us on a regular basis and will establish and adjust any reserves as appropriate to reflect our assessment of the then current status of the matters.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

Item 5. Market for Registrant's Common Equity, Related Stockholder Matters and Issuer Purchases of Equity Securities

Market Information

Our common stock trades on the NYSE under the symbol "CXO." The following table shows, for the periods indicated, the high and low sales prices for our common stock, as reported on the NYSE.

	Price Per Share High	Price Per Share Low
2013:		
First Quarter	$ 99.39	$ 79.67
Second Quarter	$ 97.62	$ 78.58
Third Quarter	$ 110.37	$ 83.44
Fourth Quarter	$ 122.81	$ 97.21
2014:		
First Quarter	$ 125.15	$ 94.51
Second Quarter	$ 145.70	$ 120.57
Third Quarter	$ 148.61	$ 123.94
Fourth Quarter	$ 128.05	$ 77.22

On February 24, 2015 the last sales price of our common stock as reported on the NYSE was $113.35 per share.

As of February 24, 2015, there were 963 holders of record of our common stock.

Dividend Policy

We have not paid, and do not intend to pay in the foreseeable future, cash dividends on our common stock. Covenants contained in our credit facility and the indentures governing our senior notes limit the payment of dividends on our common stock. We currently intend to retain all future earnings to fund the development and growth of our business. Any payment of future dividends will be at the discretion of our board of directors and will depend on, among other things, our earnings, financial condition, capital requirements, level of indebtedness, statutory and contractual restrictions applying to the payment of dividends and other considerations that our board of directors deems relevant. See Note 8 of the Notes to Consolidated Financial Statements included in Item 8. Financial Statements and Supplementary Data for additional information.

Repurchase of Equity Securities

Period	Total number of shares withheld (a)	Average price per share		Total number of shares purchased as part of publicly announced plans	Maximum number of shares that may yet be purchased under the plan
October 1, 2014 - October 31, 2014	82,722	$	116.02	-	
November 1, 2014 - November 30, 2014	308	$	99.89	-	
December 1, 2014 - December 31, 2014	1,716	$	84.77	-	

(a) Represents shares that were withheld by us to satisfy tax withholding obligations of certain of our officers and key employees that arose upon the lapse of restrictions on restricted stock.

Item 6. Selected Financial Data

This section presents our selected historical consolidated financial data. The selected historical consolidated financial data presented below is not intended to replace our historical consolidated financial statements. You should read the following data along with "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" and the consolidated financial statements and related notes, each of which is included in this report.

Selected Historical Financial Information

Our results of operations for the periods presented below may not be comparable either from period to period or going forward for the following reasons:

- in March 2012, we issued $600 million in aggregate principal amount of 5.5% senior notes due 2022 at par, for which we received net proceeds of approximately $590.0 million;

- in July 2012, we closed the Three Rivers Acquisition for cash consideration of approximately $1.0 billion. The Three Rivers Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to July 2012 do not include results from the Three Rivers Acquisition;

- in August 2012, we issued $700 million in aggregate principal amount of 5.5% senior notes due 2023 at par, for which we received net proceeds of approximately $688.6 million;

- in December 2012, we sold certain of our non-core assets, a portion of which were acquired in the Three Rivers Acquisition, for approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million (included in discontinued operations);

- in June 2013, we issued $850 million in aggregate principal amount of 5.5% senior notes due 2023 at 103.75 percent of par, for which we received net proceeds of approximately $867.8 million. We used a portion of the net proceeds from the offering to fund the tender offer and redemption of the 8.625% Notes at a price of 106.922 percent of the unpaid principal amount. The remaining proceeds were used to pay down amounts outstanding on the credit facility; and

- in May 2014, we issued in a secondary public offering 7.5 million shares of our common stock at $129.00 per share, and we received net proceeds of approximately $932.0 million.

Our financial data below is derived from (i) our audited consolidated financial statements included in this report and (ii) other audited consolidated financial statements of ours not included in this report, after taking into account the necessary reclassifications to present discontinued operations.

	Years Ended December 31,				
(in thousands, except per share amounts)	**2014**	**2013**	**2012 (a)**	**2011**	**2010 (b)**
Statement of operations data:					
Total operating revenues	$ 2,660,147	$ 2,319,919	$ 1,819,814	$ 1,617,771	$ 851,443
Total operating costs and expenses	(1,570,402)	(1,702,482)	(969,251)	(814,103)	(532,004)
Income from operations	$ 1,089,745	$ 617,437	$ 850,563	$ 803,668	$ 319,439
Income from continuing operations, net of tax	$ 538,175	$ 238,922	$ 408,230	$ 419,534	$ 147,426
Income from discontinued operations, net of tax	-	12,081	23,459	128,603	56,944
Net income attributable to common shareholders	$ 538,175	$ 251,003	$ 431,689	$ 548,137	$ 204,370
Basic earnings per share:					
Income from continuing operations	$ 4.89	$ 2.28	$ 3.96	$ 4.09	$ 1.59
Income from discontinued operations, net of tax	-	0.11	0.22	1.25	0.62
Net income attributable to common shareholders	$ 4.89	$ 2.39	$ 4.18	$ 5.34	$ 2.21
Diluted earnings per share:					
Income from continuing operations	$ 4.88	$ 2.28	$ 3.93	$ 4.05	$ 1.57
Income from discontinued operations, net of tax	-	0.11	0.22	1.23	0.61
Net income attributable to common shareholders	$ 4.88	$ 2.39	$ 4.15	$ 5.28	$ 2.18
Other financial data:					
Net cash provided by operations	$ 1,673,787	$ 1,362,020	$ 1,237,478	$ 1,199,458	$ 651,582
Net cash used in investing activities	$ 2,545,996	$ 1,896,794	$ 2,240,444	$ 1,651,418	$ 2,043,457
Net cash provided by financing activities	$ 872,209	$ 531,915	$ 1,005,504	$ 451,918	$ 1,389,025
EBITDAX (c)	$ 2,033,225	$ 1,685,592	$ 1,475,628	$ 1,275,159	$ 742,994

(in thousands)	December 31, 2014	2013	2012 (a)	2011	2010 (b)
Balance sheet data:					
Cash and cash equivalents	$ 21	$ 21	$ 2,880	$ 342	$ 384
Property and equipment, net	10,206,014	8,946,048	7,993,424	6,290,118	4,913,787
Total assets	11,799,963	9,591,164	8,589,437	6,849,576	5,368,494
Long-term debt, including current maturities	3,517,320	3,630,421	3,101,103	2,080,141	1,668,521
Stockholders' equity	5,280,788	3,757,949	3,466,196	2,980,739	2,383,874

(a) The Three Rivers Acquisition closed in July 2012.

(b) In October 2010, we closed on an acquisition of oil and natural gas leases, interests, properties and related assets owned by Marbob Energy Corporation and its affiliates.

(c) EBITDAX is defined as net income, plus (1) exploration and abandonments expense, (2) depreciation, depletion and amortization expense, (3) accretion expense, (4) impairments of long-lived assets, (5) non-cash stock-based compensation expense, (6) bad debt expense, (7) (gain) loss on derivatives not designated as hedges, (8) cash receipts from (payments on) derivatives not designated as hedges, (9) loss on disposition of assets, net, (10) interest expense, (11) loss on extinguishment of debt, (12) federal and state income taxes on continuing operations and (13) similar items listed above that are presented in discontinued operations. See "Item 1. Business—Non-GAAP Financial Measures and Reconciliations."

Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations

The following discussion is intended to assist you in understanding our business and results of operations together with our present financial condition. This section should be read in conjunction with our historical consolidated financial statements and notes, as well as the selected historical consolidated financial data included elsewhere in this report. As a result of the acquisitions and divestures discussed below, many comparisons between periods will be difficult or impossible.

In July 2012, we acquired producing and non-producing assets from Three Rivers Operating Company (the "Three Rivers Acquisition") for cash consideration of approximately $1.0 billion. The Three Rivers Acquisition was primarily funded with borrowings under our credit facility. The results of operations prior to July 2012 do not include results from the Three Rivers Acquisition.

In December 2012, we closed on the sale of certain of our non-core assets for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million (included in discontinued operations). For the year ended December 31, 2012, these assets produced an average of 4,937 Boe per day.

Certain statements in our discussion below are forward-looking statements. These forward-looking statements involve risks and uncertainties. We caution that a number of factors could cause actual results to differ materially from these implied or expressed by the forward-looking statements. Please see "Cautionary Statement Regarding Forward-Looking Statements."

Overview

We are an independent oil and natural gas company engaged in the acquisition, development and exploration of producing oil and natural gas properties. Our core operations are primarily focused in the Permian Basin of Southeast New Mexico and West Texas. We refer to our three core operating areas as the (i) New Mexico Shelf, where we primarily target the Yeso formation with horizontal and vertical development, (ii) Delaware Basin, where we use horizontal drilling and technology to target the Bone Spring formation, including the Avalon shale, Bone Spring sands, and the Wolfcamp shale formation, and (iii) Texas Permian in the Midland Basin, where we target the Wolfcamp and Spraberry formations with horizontal and vertical development. Oil comprised 58.1 percent of our 637.2 MMBoe of estimated proved reserves at December 31, 2014 and 64.4 percent of our 40.9 MMBoe of production for 2014. We seek to operate the wells in which we own an interest, and we operated wells that accounted for 92.3 percent of our proved developed producing PV-10 and 79.5 percent of our approximately 7,208 gross wells at December 31, 2014. By controlling operations, we are able to more effectively manage the cost and timing of exploration and development of our properties, including the drilling and stimulation methods used.

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Financial and Operating Performance

Our financial and operating performance for 2014 included the following highlights:

- Net income was $538.2 million ($4.88 per diluted share), as compared to net income of $251.0 million ($2.39 per diluted share) in 2013. The increase in earnings was primarily due to:

§ $340.2 million increase in oil and natural gas revenues as a result of a 22 percent increase in production partially offset by a 6 percent decrease in commodity price realizations per Boe (excluding the effects of derivative activities);

§ $890.9 million gain on derivatives not designated as hedges for the year ended December 31, 2014, as compared to $123.7 million loss during the year ended December 31, 2013, primarily related to commodity future price curves at the respective measurement periods; and

partially offset by:

§ $447.2 million in non-cash impairment charges in 2014 primarily due to a decrease in our estimated future cash flows related to management's outlook of future commodity prices and costs, as compared to a $65.4 million non-cash impairment charge in 2013 due primarily to downward adjustments to our economically recoverable proved reserves;

§ $175.3 million increase in exploration and abandonments in 2014 as compared to 2013;

§ $207.1 million increase in depreciation, depletion and amortization expense, primarily due to increased production from costs incurred associated with new wells that were successfully drilled and completed in 2013 and 2014;

§ $82.9 million increase in oil and natural gas production costs due in part to increased production related to our wells successfully drilled and completed in 2013 and 2014;

§ $34.3 million increase in general and administrative expense due to an increase in the number of employees and related personnel expenses to manage our increased activities related to our increased drilling and exploration activities; and

§ $199.5 million increase in income tax expense due to the increase in income before income taxes resulting in a 37.1 percent effective tax rate.

- Average daily sales volumes increased by 22 percent from 92,150 Boe per day during 2013 to 111,987 Boe per day during 2014. The increase was primarily attributable to our successful drilling efforts during 2013 and 2014, partially offset by normal production declines.

- Net cash provided by operating activities increased by approximately $311.8 million to $1,673.8 million for 2014, as compared to $1,362.0 million in 2013, primarily due to an increase in oil and natural gas revenues and a smaller negative variance in working capital changes, which adjust for the timing of receipts and payments of actual cash, partially offset by increases in oil and natural gas production costs.

- Long-term debt decreased by approximately $0.1 billion during 2014, primarily due to utilizing a portion of the net proceeds from our equity offering to repay borrowings under our credit facility, partially offset by capital expenditures primarily related to our drilling program in excess of our cash flows.

Commodity Prices

Our results of operations are heavily influenced by commodity prices. Commodity prices may fluctuate widely in response to (i) relatively minor changes in the supply of and demand for oil, natural gas and natural gas liquids, (ii) market uncertainty and (iii) a variety of additional factors that are beyond our control. Factors that may impact future commodity prices, including the price of oil, natural gas and natural gas liquids, include:

- continuing economic uncertainty worldwide;
- political and economic developments in oil and natural gas producing regions, including Africa, South America and the Middle East;
- the extent to which members of the Organization of Petroleum Exporting Countries and other oil exporting nations are able to continue to manage oil prices and production controls;
- technological advances affecting energy consumption and energy supply;
- the effect of energy conservation efforts;
- the price and availability of alternative fuels;
- domestic and foreign governmental regulations, including limits on the United States' ability to export crude oil, and taxation;
- the level of global inventories;
- the proximity, capacity, cost and availability of pipelines and other transportation facilities, as well as the availability of commodity processing and gathering and refining capacity;

- the quality of the oil we produce;
- the overall global demand for oil natural gas and natural gas liquids;
- the domestic and foreign supply of oil, natural gas and natural gas liquids; and
- overall North American oil and natural gas supply and demand fundamentals, including:
- the United States economy impact,
- weather conditions, and
- the potential for liquefied natural gas deliveries to and exports from the United States.

Although we cannot predict the occurrence of events that may affect future commodity prices or the degree to which these prices will be affected, the prices for any commodity that we produce will generally approximate current market prices in the geographic region of the production. From time to time, we expect that we may economically hedge a portion of our commodity price risk to mitigate the impact of price volatility on our business. See Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our commodity derivative positions at December 31, 2014.

Oil and natural gas prices have been subject to significant fluctuations during the past several years. Average oil prices have decreased during 2014 compared to 2013 while natural gas prices have increased over the comparative same period. The following table sets forth the average NYMEX oil and natural gas prices for the years ended December 31, 2014, 2013 and 2012, as well as the high and low NYMEX price for the same periods:

	Years Ended December 31, 2014	2013	2012
Average NYMEX prices:			
Oil (Bbl)	$ 92.94	$ 98.05	$ 94.19
Natural gas (MMBtu)	$ 4.27	$ 3.73	$ 2.83
High and Low NYMEX prices:			
Oil (Bbl):			
High	$ 107.26	$ 110.53	$ 109.77
Low	$ 53.27	$ 86.68	$ 77.69
Natural gas (MMBtu):			
High	$ 6.15	$ 4.46	$ 3.90
Low	$ 2.89	$ 3.11	$ 1.91

Further, the NYMEX oil price and NYMEX natural gas price reached highs and lows of $53.53 and $44.45 per Bbl and $3.23 and $2.58 per MMBtu, respectively, during the period from January 1, 2015 to February 24, 2015. At February 24, 2015, the NYMEX oil price and NYMEX natural gas price were $49.28 per Bbl and $2.90 per MMBtu, respectively.

Historically, approximately 55 to 80 percent of our total natural gas revenues have been derived from the value of the natural gas liquids contained in our natural gas, with the remaining portion coming from the value of the dry natural gas residue. Because of our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues historically, our realized natural gas price (excluding the effects of derivatives) has reflected a price greater than the related NYMEX natural gas price. The Mont Belvieu prices for a blended barrel of natural gas liquids in 2014 ranged from a high of $43.76 per Bbl to a low of $19.99 per Bbl. Further, the Mont Belvieu price for a blended barrel of natural gas liquids for January 2015 was $18.08 per Bbl.

Recent Events

2015 capital budget. In January 2015, we announced our updated 2015 capital budget of approximately $2.0 billion, of which approximately 90 percent of the drilling and completion costs will be dedicated to horizontal drilling. Our 2015 capital program is expected to continue focusing on drilling in the Delaware Basin and Midland Basin. The 2015 capital budget, based on our current expectations of commodity prices and cost, will exceed our cash flow. We expect our cash flow and borrowings under our credit facility will be sufficient to fund our budgeted capital expenditure needs during 2015. However, if we experience sustained commodity prices lower than our forecasted pricing without sufficient cost reductions, we may adjust our capital budget to preserve financial strength.

(in billions)		**2015 Capital Budget**
Drilling and completion costs:		
Delaware Basin	$	1.3
Texas Permian		0.3
New Mexico Shelf		0.2
Total drilling and completion costs		1.8
Other capital (a)		0.2
Total	$	2.0

(a) Includes facilities, leasehold acquisitions, a midstream project, geological and geophysical data and other capital.

Weather event. Heavy rainfall and flooding during the latter part of September 2014 disrupted our operations, primarily in southeast New Mexico, causing shut-in production, road closures and drilling and completion delays. We estimate this weather-related downtime negatively impacted production for the quarter ended December 31, 2014 by approximately 1.6 MBoepd. We estimate that during the quarter ended December 31, 2014 approximately $1.7 million of repairs was due to this event.

Common stock offering. In May 2014, we issued in a secondary public offering approximately 7.5 million shares of our common stock at $129.00 per share, and we received net proceeds of approximately $932.0 million. We used a portion of the net proceeds from this offering to repay all outstanding borrowings under our credit facility and plan to use the remainder for general corporate purposes, including funding our drilling program and capital commitments associated with the midstream joint venture.

Delaware Basin midstream agreements. On May 9, 2014, we signed an agreement to own 50 percent of a joint venture, Alpha Crude Connector, LLC (“ACC”), which will build a crude oil pipeline to gather and transport oil production in the northern Delaware Basin. Additionally, on May 9, 2014, we entered into a ten year Crude Petroleum

Dedication and Transportation Agreement with ACC to transport our oil production in the northern Delaware Basin. We expect to receive improved price realizations on our crude oil subject to this dedication agreement due to reduced transportation costs and increased marketing influence due to concentrated volumes.

Amended and restated credit facility. On May 9, 2014, we amended and restated our credit facility, increasing our borrowing base from $3.0 billion to $3.25 billion, but maintaining the aggregate lender commitments at $2.5 billion. The maturity date of the amended and restated credit facility is May 9, 2019. We expensed approximately $4.3 million in capitalized deferred loan costs incurred with the previous credit facility.

Derivative Financial Instruments

Derivative financial instrument exposure. At December 31, 2014, the fair value of our financial derivatives was a net asset of $752.7 million. All of our counterparties to these financial derivatives are parties to our credit facility and have their outstanding debt commitments and derivative exposures collateralized pursuant to our credit facility. Under the terms of our financial derivative instruments and their collateralization under our credit facility, we do not have exposure to potential “margin calls” on our financial derivative instruments. We currently have no reason to believe that our counterparties to these commodity derivative contracts are not financially viable. Our credit facility does not allow us to offset amounts we may owe a lender against amounts we may be owed related to our financial instruments with such party.

New commodity derivative contracts. After December 31, 2014, we entered into the following additional oil price swaps and oil basis swaps to hedge additional amounts of our estimated future production:

	First Quarter	**Second Quarter**	**Third Quarter**	**Fourth Quarter**	**Total**
Oil Swaps: (a)					
2015:					
Volume (Bbl)	-	660,000	660,000	660,000	1,980,000
Price per Bbl	$ -	$ 56.60	$ 56.60	$ 56.60	$ 56.60
2016:					
Volume (Bbl)	180,000	180,000	180,000	2,610,000	3,150,000
Price per Bbl	$ 61.04	$ 61.04	$ 61.04	$ 62.48	$ 62.23
Oil Basis Swaps: (b)					
2016:					
Volume (Bbl)	364,000	364,000	368,000	368,000	1,464,000
Price per Bbl	$ (2.48)	$ (2.48)	$ (2.48)	$ (2.48)	$ (2.48)

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.

Results of Operations

The following table sets forth summary information concerning our production and operating data from continuing operations for the years ended December 31, 2014, 2013 and 2012. The table below excludes production and operating data that we have classified as discontinued operations, which is more fully described in Note 13 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data." The actual historical data in this table excludes results from the Three Rivers Acquisition for periods prior to July 2012. Because of normal production declines, increased or decreased drilling activities, fluctuations in commodity prices and the effects of acquisitions or divestitures, the historical information presented below should not be interpreted as being indicative of future results.

	Years Ended December 31,		
	2014	2013	2012
Production and operating data from continuing operations:			
Net production volumes:			
Oil (MBbl)	26,319	21,126	16,859
Natural gas (MMcf)	87,336	75,054	66,613
Total (MBoe)	40,875	33,635	27,961
Average daily production volumes:			
Oil (Bbl)	72,107	57,879	46,063
Natural gas (Mcf)	239,277	205,627	182,003
Total (Boe)	111,987	92,150	76,397
Average prices:			
Oil, without derivatives (Bbl)	$ 83.17	$ 91.76	$ 87.96
Oil, with derivatives (Bbl) (a)	$ 86.07	$ 89.79	$ 89.29
Natural gas, without derivatives (Mcf)	$ 5.39	$ 5.08	$ 5.06
Natural gas, with derivatives (Mcf) (a)	$ 5.34	$ 5.21	$ 5.07
Total, without derivatives (Boe)	$ 65.08	$ 68.97	$ 65.08
Total, with derivatives (Boe) (a)	$ 66.84	$ 68.01	$ 65.93
Operating costs and expenses per Boe:			
Lease operating expenses and workover costs	$ 8.05	$ 7.85	$ 6.90
Oil and natural gas taxes	$ 5.12	$ 5.69	$ 5.39
Depreciation, depletion and amortization	$ 23.97	$ 22.97	$ 20.56
General and administrative	$ 4.99	$ 5.04	$ 4.79

(a) Includes the effect of cash receipts from (payments on) derivatives not designated as hedges:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Cash receipts from (payments on) derivatives not designated as hedges:			
Oil derivatives	$ 76,335	$ (41,616)	$ 22,411
Natural gas derivatives	(4,352)	9,275	1,125
Total	$ 71,983	$ (32,341)	$ 23,536

The presentation of average prices with derivatives is a non-GAAP measure as a result of including the cash receipts from (payments on) commodity derivatives that are presented in our statements of cash flows. This presentation of average prices with derivatives is a means by which to reflect the actual cash performance of our commodity derivatives for the respective periods and presents oil and natural gas prices with derivatives in a manner consistent with the presentation generally used by the investment community.

The following table sets forth summary information from our discontinued operations concerning our production and operating data for the year ended December 31, 2012. The discontinued operations presentation is the result of reclassifying the results of operations from the divestiture of our non-core assets in December 2012 which is more fully described in Note 13 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

	Year Ended December 31, 2012	
Production and operating data from discontinued operations:		
Net production volumes:		
Oil (MBbl)		1,144
Natural Gas (Mcf)		3,978
Total (MBoe)		1,807
Average daily production volumes:		
Oil (Bbl)		3,126
Natural gas (Mcf)		10,869
Total (Boe)		4,937
Average prices:		
Oil, without derivatives (Bbl)	$	88.60
Natural gas, without derivatives (Mcf)	$	4.67
Total, without derivatives (Boe)	$	66.37
Operating costs and expenses per Boe:		
Lease operating expenses and workover costs	$	12.95
Oil and natural gas taxes	$	6.01
Depreciation, depletion and amortization	$	16.68
General and administrative (a)	$	(1.38)

(a) Represents the fees received from third-parties for operating oil and natural gas properties that were sold. We reflect these fees as a reduction of general and administrative expenses.

The following tables present selected production and operating data for the fields which represent greater than 15 percent of our total proved reserves at December 31, 2014, 2013 and 2012:

	Year Ended December 31, 2014	
	South Basin Avalon	Yeso Central
Production and operating data:		
Net production volumes:		
Oil (MBbl)	5,227	2,991
Natural gas (MMcf)	23,027	13,936
Total (MBoe)	9,065	5,314
Average prices:		
Oil, without derivatives (Bbl)	$ 82.04	$ 86.06
Natural gas, without derivatives (Mcf)	$ 4.91	$ 6.35
Total, without derivatives (Boe)	$ 59.78	$ 65.08
Production costs per Boe:		
Lease operating expenses including workovers	$ 5.00	$ 8.56
Oil and natural gas taxes	$ 4.38	$ 5.72

	Year Ended December 31, 2013	
	Wolfberry West	Yeso Central
Production and operating data:		
Net production volumes:		
Oil (MBbl)	3,509	2,157
Natural gas (MMcf)	11,238	8,122
Total (MBoe)	5,382	3,511
Average prices:		
Oil, without derivatives (Bbl)	$ 93.05	$ 90.42
Natural gas, without derivatives (Mcf)	$ 6.15	$ 6.24
Total, without derivatives (Boe)	$ 73.51	$ 70.00
Production costs per Boe:		
Lease operating expenses including workovers	$ 9.30	$ 12.38
Oil and natural gas taxes	$ 5.68	$ 6.25

	Year Ended December 31, 2012	
	Wolfberry West	Yeso Central
Production and operating data:		

Net production volumes:				
Oil (MBbl)		3,402		4,053
Natural gas (MMcf)		10,399		14,915
Total (MBoe)		5,135		6,539
Average prices:				
Oil, without derivatives (Bbl)	$	88.22	$	88.52
Natural gas, without derivatives (Mcf)	$	6.14	$	6.28
Total, without derivatives (Boe)	$	70.87	$	69.19
Production costs per Boe:				
Lease operating expenses including workovers	$	7.45	$	7.43
Oil and natural gas taxes	$	5.11	$	5.97

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

Oil and natural gas revenues. Revenue from oil and natural gas operations was $2,660.1 million for the year ended December 31, 2014, an increase of $340.2 million (15 percent) from $2,319.9 million for the year ended December 31, 2013. This increase was primarily due to increased production due to our successful drilling efforts during 2013 and 2014 as well as an increase in the realized natural gas prices, partially offset by the decrease in realized oil prices. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 26,319 MBbl for the year ended December 31, 2014, an increase of 5,193 MBbl (25 percent) from 21,126 MBbl for the year ended December 31, 2013;

- average realized oil price (excluding the effects of derivative activities) was $83.17 per Bbl during the year ended December 31, 2014, a decrease of 9 percent from $91.76 per Bbl during the year ended December 31, 2013. For the year ended December 31, 2014 and 2013, we realized approximately 89.5 percent and 93.6 percent, respectively, of the average NYMEX oil prices for the respective periods. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil has a direct effect on our realized oil price. For the years ended December 31, 2014 and 2013, the market basis differential between WTI-Midland and WTI-Cushing (sweet barrel) was a price reduction of $6.91 per Bbl and $2.63 per Bbl, respectively;

- total natural gas production was 87,336 MMcf for the year ended December 31, 2014, an increase of 12,282 MMcf (16 percent) from 75,054 MMcf for the year ended December 31, 2013; and

- average realized natural gas price (excluding the effects of derivative activities) was $5.39 per Mcf during the year ended December 31, 2014, an increase of 6 percent from $5.08 per Mcf during the year ended December 31, 2013. For the years ended December 31, 2014 and 2013, we realized approximately 126.2 percent and 136.2 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Historically, approximately 55 to 80 percent of our total natural gas revenues were derived from the value of the natural gas liquids, with the remaining portion coming from the value of the dry natural gas residue. Because of our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues historically, our realized natural gas price (excluding the effects of derivatives) has reflected a price greater than the related NYMEX natural gas price. The deterioration of our realization percentage between comparable periods was primarily related to a combination of (i) a higher average NYMEX natural gas price between comparable periods ($4.27 per MMBtu in 2014 compared to $3.73 per MMBtu in 2013) and (ii) a lower price being received for the value of our natural gas liquids included within our natural gas revenue stream. We estimate that between the comparable periods, the value we received per gallon of natural gas liquids decreased approximately 4 percent, which is primarily the result of an increase in the supply of natural gas liquids from the significant industry drilling in liquid-prone areas.

Heavy rainfall and flooding during the latter part of September 2014 disrupted our operations, primarily in southeast New Mexico, causing shut-in production, road closures and drilling and completion delays. We estimate this weather-related downtime negatively impacted production for the quarter ended December 31, 2014 by approximately 1.6 MBoepd. We estimate that during the quarter ended December 31, 2014 approximately $1.7 million of repairs was due to this event.

During the fourth quarter of 2013, severe winter weather events across the Permian Basin had a significant impact on our production and drilling operations. We experienced widespread power outages, heavy icing, trucking curtailments, and facility freeze-ups across all three of our core areas. We estimate that these weather events reduced our volumes for 2013 by approximately 114 MBoe.

During 2013, the natural gas processing infrastructure in our New Mexico Shelf area struggled to support the rapid growth of natural gas supply due to increased drilling by us and other producers over the recent past. During the second quarter of 2013, we noted that (i) certain additional natural gas processing capacity that was scheduled to be operational had been delayed to later in 2013 and (ii) approximately 20 MMcf per day of natural gas processing capacity, located near our recent drilling activity, had been taken out of service due to mechanical issues. During the second half of 2013, some of the effects of these infrastructure issues were mitigated through (i) temporarily moving additional natural gas volumes to other third-party processors and (ii) an improvement in operating run times and operational efficiencies of certain third-party processors. We estimate these infrastructure constraints, which in part caused us to flare limited natural gas volumes, reduced our volumes for 2013 by approximately 515 MBoe.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2014 and 2013:

	Years Ended December 31,			
	2014		2013	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Lease operating expenses	$ 310,284	$ 7.59	$ 248,436	$ 7.39
Taxes:				
Ad valorem	20,775	0.51	22,979	0.68
Production	188,348	4.61	168,585	5.01
Workover costs	18,967	0.46	15,436	0.46
Total oil and natural gas production expenses	$ 538,374	$ 13.17	$ 455,436	$ 13.54

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are related to commodity prices.

Lease operating expenses were $310.3 million ($7.59 per Boe) for the year ended December 31, 2014, which was an increase of $61.9 million (25 percent) from $248.4 million ($7.39 per Boe) for the year ended December 31, 2013. The increase in lease operating expenses was primarily due to increased production associated with our wells successfully drilled and completed in 2013 and 2014. The increase in lease operating expenses per Boe was primarily due to expansion of our production in areas with underdeveloped infrastructure. We estimate that during the year ended December 31, 2014 approximately $2.5 million ($0.06 per Boe) of repairs was due to weather events.

Production taxes per unit of production were $4.61 per Boe during the year ended December 31, 2014, a decrease of 8 percent from $5.01 per Boe during the year ended December 31, 2013. The decrease was directly related to the decrease in oil prices. Over the same period, our per Boe prices (excluding the effects of derivatives) decreased 6 percent.

Workover expenses were approximately $19.0 million and $15.4 million for the years ended December 31, 2014 and 2013, respectively. The 2014 and 2013 expenses related primarily to routine workovers performed to increase or restore production.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2014 and 2013:

(in thousands)	Years Ended December 31, 2014	2013
Geological and geophysical	$ 19,268	$ 27,690
Exploratory dry hole costs	44,180	29,514
Leasehold abandonments	217,326	49,758
Other	4,047	2,587
Total exploration and abandonments	$ 284,821	$ 109,549

Our geological and geophysical expense primarily consists of the costs of acquiring and processing geophysical data and core analysis, mostly related to our Delaware Basin and Texas Permian areas. During the year ended December 31, 2014, we acquired geological and geophysical data related to our northern Delaware Basin acreage. During the year ended December 31, 2013, we had multiple seismic projects ongoing, which were completed during the second half of 2013. These projects were related to our increase in drilling and exploration activity in the Delaware Basin and Texas Permian core areas.

During the fourth quarter of 2014, we completed our assessment of our activity in the outer limits of our southern Delaware Basin acreage position. Based on our analysis and marginal results of our exploratory wells on this acreage, we have no further plans to invest in this position. Accordingly, we recognized approximately $32.7 million in exploratory dry hole costs and approximately $96.4 million in leasehold abandonments in 2014.

During 2014, we recognized exploratory dry hole costs of approximately $44.2 million. In addition to the $32.7 million (discussed above), we recognized $6.3 million of dry hole costs related to two New Mexico Shelf wells that encountered mechanical issues while drilling and one Delaware Basin well targeting the Brushy Canyon horizon that was testing the outer limits of our acreage.

During the year ended December 31, 2014, we recognized leasehold abandonment expense of approximately $217.3 million primarily related to (i) the Delaware Basin abandonment discussed above, as well as (ii) an $86.0 million charge related to properties in our Texas Permian core area that, based on our historical results and our estimate of reduced future commodity price, we have no future intent to drill based on expected low rates of return. The remaining abandonment charges are associated with expiring acreage and acreage determined to be outside of our economically productive reservoirs.

During the fourth quarter of 2013, we completed our assessment of our activity on our northern Midland Basin acreage position. Our initial wells on this acreage were uneconomic. We have no further plans to invest in this position. Accordingly, we recognized $14.8 million in exploratory dry hole costs and $34.9 million in leasehold abandonments in 2013.

Our exploratory dry hole costs during the year ended December 31, 2013 were primarily related to (i) partial expensing of unsuccessful horizontal laterals on two wells in the Delaware Basin, (ii) an unsuccessful vertical well in the New Mexico Shelf area that was testing the eastern boundaries of the area, (iii) partial expensing of unsuccessful horizontal laterals in the New Mexico Shelf area and (iv) the northern Midland Basin wells (noted above).

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2014 and 2013:

	Years Ended December 31,			
	2014		2013	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 960,931	$ 23.51	$ 755,952	$ 22.48
Depreciation of other property and equipment	17,348	0.42	15,195	0.45

Amortization of intangible asset - operating rights		1,461		0.04		1,461		0.04
Total depletion, depreciation and amortization	$	979,740	$	23.97	$	772,608	$	22.97
Oil price used to estimate proved oil reserves at period end	$	91.48			$	93.42		
Natural gas price used to estimate proved natural gas reserves at period end	$	4.35			$	3.67		

Depletion of proved oil and natural gas properties was $960.9 million ($23.51 per Boe) for the year ended December 31, 2014, an increase of $204.9 million (27 percent) from $756.0 million ($22.48 per Boe) for the year ended December 31, 2013. The increase in depletion expense was primarily due to increased production associated with new wells that were successfully drilled and completed in 2013 and 2014 and a higher per unit depletion rate. The increase in depletion expense per Boe was primarily due to (i) drilling deeper, higher cost wells in less proven areas and (ii) increasing production in our newer asset areas, such as the Delaware Basin, where we have a higher depletion rate than our legacy assets, such as the New Mexico Shelf.

The increase in depreciation expense was primarily associated with our increase in depreciation of other property and equipment related to buildings and other items as a result of our increased number of employees.

Impairment of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to a decrease in our estimated future cash flows related to management’s outlook of future commodity prices and costs, we recognized a non-cash charge against earnings of $447.2 million during the year ended December 31, 2014, which was primarily attributable to

(i) non-core properties in our Delaware Basin area, (ii) properties producing from the Grayburg San Andres reservoir in our New Mexico Shelf area and (iii) properties producing from the Canyon and Wolfcamp reservoirs primarily in Irion and Glasscock counties in our Texas Permian core area. Due primarily to downward adjustments to the economically recoverable proved reserves associated with declines in well performance and decreases in estimated realized natural gas prices, we recognized a non-cash charge against earnings of $65.4 million during the second quarter of 2013, which was primarily attributable to non-core natural gas related properties in our New Mexico Shelf area.

It is reasonably possible that the estimate of undiscounted future net cash flows may change in the future resulting in the need to further impair carrying values. The primary factors that may affect management's estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves and (iv) results of future drilling activities.

Additionally, based on the factors above as of December 31, 2014, we determined that undiscounted future cash flows attributable to certain depletion groups indicated that their carrying amounts were expected to be recovered; however, they may be at risk for impairment if management's estimates of future cash flows further decline. We estimate that if these depletion groups were to become impaired in a future period, we may recognize a significant non-cash impairment in that period.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2014 and 2013:

	Years Ended December 31,			
	2014		2013	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 180,278	$ 4.41	$ 153,199	$ 4.55
Non-cash stock-based compensation	47,130	1.15	35,078	1.04
Less: Third-party operating fee reimbursements	(23,247)	(0.57)	(18,462)	(0.55)
Total general and administrative expenses	$ 204,161	$ 4.99	$ 169,815	$ 5.04

General and administrative expenses were approximately $204.2 million ($4.99 per Boe) for the year ended December 31, 2014, an increase of $34.4 million (20 percent) from $169.8 million ($5.04 per Boe) for the year ended December 31, 2013.

The increase in cash general and administrative expenses of approximately $27.1 million was primarily due to an increase in the number of employees and related personnel expenses. The increase in non-cash stock-based compensation of approximately $12.1 million was primarily due to (i) an increase in the number of employees in order to manage our increased activities directly related to our increased drilling and exploration activities and (ii) a $2.3 million ($0.07 per Boe) net benefit to stock-based compensation related to forfeitures and modifications of stock-based awards associated with two officer resignations included in 2013.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $23.2 million and $18.5 million during the years ended December 31, 2014 and 2013, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in third-party operating fee reimbursements was primarily due to increased reimbursements attributable to more wells operated as a result of continued drilling activity period over period.

(Gain) loss on derivatives not designated as hedges. The following table sets forth the gain (loss) on derivatives not designated as hedges for the years ended December 31, 2014 and 2013:

	Years Ended December 31,	
(in thousands)	**2014**	**2013**
Gain (loss) on derivatives not designated as hedges:		
Oil derivatives	$ 869,421	$ (133,890)
Natural gas derivatives	21,496	10,238
Total	$ 890,917	$ (123,652)

The following table represents our cash receipts from (payments on) derivatives not designated as hedges for the years ended December 31, 2014 and 2013:

	Years Ended December 31,	
(in thousands)	**2014**	**2013**
Cash receipts from (payments on) derivatives not designated as hedges:		
Oil derivatives	$ 76,335	$ (41,616)
Natural gas derivatives	(4,352)	9,275
Total	$ 71,983	$ (32,341)

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which could be significant. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, while to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2014 and 2013:

	Years Ended December 31,	
(dollars in thousands)	**2014**	**2013**

Interest expense	$	216,661	$	218,581
Capitalized interest		2,282		-
Interest expense, excluding impact of capitalized interest	$	218,943	$	218,581
Weighted average interest rate - credit facility		2.4%		2.3%
Weighted average interest rate - senior notes		5.9%		6.1%
Total weighted average interest rate		5.8%		5.7%
Weighted average credit facility balance	$	144,966	$	327,488
Weighted average senior notes balance		3,350,000		3,117,222
Total weighted average debt balance	$	3,494,966	$	3,444,710

The increase in weighted average debt balance during the year ended December 31, 2014 as compared to the corresponding period in 2013 was due to capital expenditures primarily related to our drilling program in excess of our cash flows, offset by cash received from our equity offering. The increase in interest expense was due to an overall increase in the weighted average debt balance and interest rate.

Loss on extinguishment of debt. We recorded a loss on extinguishment of debt of $4.3 million and $28.6 million for the years ended December 31, 2014 and 2013, respectively. The 2014 amount represents the proportional amount of unamortized deferred loan costs associated with banks with lesser commitments in the amended credit facility syndicate. The 2013 amount includes approximately $20.4 million associated with the premium paid for the tender and redemption of the 8.625% Notes, approximately $5.5 million of unamortized deferred loan costs associated with the 8.625% Notes and approximately $2.7 million of unamortized discount on the 8.625% Notes.

Income tax provisions. We recorded an income tax expense of $317.8 million and $118.2 million for the years ended December 31, 2014 and 2013, respectively. The effective income tax rate for the years ended December 31, 2014 and 2013 was 37.1 percent and 33.1 percent, respectively.

We recorded a $7.9 million and $21.9 million income tax benefit in the fourth quarter of 2014 and 2013, respectively, due to a decrease in our estimated overall state tax rate utilized to record our net deferred tax liability. During 2013, the state of New Mexico passed legislation to phase in a tax rate reduction over the next five years from 7.6 percent in 2013 to 5.9 percent in 2018. Additionally, we continuously evaluate the state apportionment, and based on our current forecast, along with the New Mexico rate declines, we have revised our state rate. During 2014, the change in our blended state rate did not have a material effect on our overall effective tax rate. Excluding the effect of the New Mexico state rate reduction, our effective rate would have been 39.2 percent in 2013, which would approximate a more “normalized” effective income tax rate.

Income from discontinued operations, net of tax. In December 2012, we closed the sale of certain of our non-core assets for cash consideration of approximately $503.1 million. As a result of post-closing adjustments during the year ended December 31, 2013, we made a positive adjustment to gain (loss) on disposition of assets of approximately $19.6 million. We recognized income from discontinued operations, net of tax of $12.1 million for the year ended December 31, 2013.

The results of operations of these assets are reported as discontinued operations in the accompanying consolidated statements of operations, and are described in more detail in Note 13 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data.”

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

Oil and natural gas revenues. Revenue from oil and natural gas operations was $2,319.9 million for the year ended December 31, 2013, an increase of $500.1 million (27 percent) from $1,819.8 million for the year ended December 31, 2012. This increase was primarily due to an increase in the realized oil price and increased production due to (i) successful drilling efforts during 2012 and 2013 and (ii) production from the Three Rivers Acquisition, which closed in July 2012. Specific factors affecting oil and natural gas revenues include the following:

- total oil production was 21,126 MBbl for the year ended December 31, 2013, an increase of 4,267 MBbl (25 percent) from 16,859 MBbl for the year ended December 31, 2012;

- average realized oil price (excluding the effects of derivative activities) was $91.76 per Bbl during the year ended December 31, 2013, an increase of 4 percent from $87.96 per Bbl during the year ended December 31, 2012. For the year ended December 31, 2013 and 2012, we realized approximately 93.6 percent and 93.4 percent, respectively, of the average NYMEX oil prices for the respective periods. The basis differential between the location of Midland, Texas and Cushing, Oklahoma (NYMEX pricing location) for our oil has a direct effect on our realized oil price. For the years ended December 31, 2013 and 2012, the market basis differential between WTI-Midland and WTI-Cushing (sweet barrel) was a price reduction of $2.63 per Bbl and $2.91 per Bbl, respectively;

- total natural gas production was 75,054 MMcf for the year ended December 31, 2013, an increase of 8,441 MMcf (13 percent) from 66,613 MMcf for the year ended December 31, 2012; and

- average realized natural gas price (excluding the effects of derivative activities) was $5.08 per Mcf during the year ended December 31, 2013, a slight increase from $5.06 per Mcf during the year ended December 31, 2012. For the years ended December 31, 2013 and 2012, we realized approximately 136.2 percent and 178.8 percent, respectively, of the average NYMEX natural gas prices for the respective periods. Historically, approximately 55 to 80 percent of our total natural gas revenues were derived from the value of the natural gas liquids, with the remaining portion coming from the value of the dry natural gas residue. Because of our liquids-rich natural gas stream and the related value of the natural gas liquids being included in our natural gas revenues historically, our realized natural gas price (excluding the effects of derivatives) has reflected a price greater than the related NYMEX natural gas price. The deterioration of our realization percentage between comparable periods was primarily related to a combination of (i) a higher average NYMEX natural gas price between comparable periods ($3.73 per MMBtu in 2013 compared to $2.83 per MMBtu in 2012) and (ii) a lower price being received for the value of our natural gas liquids included within our natural gas revenue stream. We estimate that between the comparable periods, the value we received per gallon of natural gas liquids decreased approximately 13 percent, which is primarily the result of an increase in the supply of natural gas liquids from the significant industry drilling in liquid-prone areas.

During the fourth quarter of 2013, severe winter weather events across the Permian Basin had a significant impact on our production and drilling operations. We experienced widespread power outages, heavy icing, trucking curtailments, and facility freeze-ups across all three of our core areas. We estimate that these weather events reduced our volumes for 2013 by approximately 114 MBoe.

The natural gas processing infrastructure in our New Mexico Shelf area struggled to support the rapid growth of natural gas supply due to increased drilling by us and other producers over the recent past. During the second quarter of 2013, we noted that (i) certain additional natural gas processing capacity that was scheduled to be operational had been delayed to later in 2013 and (ii) approximately 20 MMcf per day of natural gas processing capacity, located near our recent drilling activity, had been taken out of service due to mechanical issues, which we expect to return to service during the first half of 2014. During the second half of 2013, some of the effects of these infrastructure issues were mitigated through (i) temporarily moving additional natural gas volumes to other third-party processors and (ii) an improvement in operating run times and operational efficiencies of certain third-party processors. We estimate these infrastructure constraints, which in part caused us to flare limited natural gas volumes, reduced our volumes for 2013 by approximately 515 MBoe. As a result, we noted during the second quarter of 2013 that we were redirecting a portion of our remaining New Mexico Shelf drilling budget to other areas, such as the Delaware Basin, until sufficient natural gas processing infrastructure is implemented and performing at consistent levels.

Production expenses. The following table provides the components of our total oil and natural gas production costs for the years ended December 31, 2013 and 2012:

	Years Ended December 31,							
	2013				2012			
(in thousands, except per unit amounts)		**Amount**		**Per Boe**		**Amount**		**Per Boe**
Lease operating expenses	$	248,436	$	7.39	$	182,716	$	6.53
Taxes:								
Ad valorem		22,979		0.68		13,695		0.49
Production		168,585		5.01		137,106		4.90
Workover costs		15,436		0.46		10,226		0.37
Total oil and natural gas production expenses	$	455,436	$	13.54	$	343,743	$	12.29

Among the cost components of production expenses, we have some control over lease operating expenses and workover costs on properties we operate, but production and ad valorem taxes are directly related to commodity price changes.

Lease operating expenses were $248.4 million ($7.39 per Boe) for the year ended December 31, 2013, which was an increase of $65.7 million (36 percent) from $182.7 million ($6.53 per Boe) for the year ended December 31, 2012. The increase in lease operating expenses was primarily due to increased continuing operations production from our wells successfully drilled and completed in 2012 and 2013 and the acquisitions in 2012. The increase in lease operating expenses per Boe was primarily due to (i) expansion of our production in areas with underdeveloped infrastructure causing a broader use of rental equipment, (ii) increased lease operating expenses per Boe related to our properties acquired in the Three Rivers Acquisition as compared to our legacy properties and (iii) some minimal costs increases in services.

Ad valorem taxes have increased primarily as a result of increased valuations of our Texas properties and the increase in the number of wells primarily associated with our 2012 and 2013 drilling activity in our Texas Permian area, the Texas portion of the Delaware Basin and the Texas properties acquired in the Three Rivers Acquisition.

Production taxes per unit of production were $5.01 per Boe during the year ended December 31, 2013, an increase of 2 percent from $4.90 per Boe during the year ended December 31, 2012. The increase was directly related to the increase in commodity prices. Over the same period, our per Boe prices (excluding the effects of derivatives) increased 6 percent.

Workover expenses were approximately $15.4 million and $10.2 million for the years ended December 31, 2013 and 2012, respectively. The 2013 and 2012 amounts related primarily to routine workovers in the Texas Permian and New Mexico Shelf areas performed to increase or restore production.

Exploration and abandonments expense. The following table provides a breakdown of our exploration and abandonments expense for the years ended December 31, 2013 and 2012:

	Years Ended December 31,	
(in thousands)	**2013**	**2012**
Geological and geophysical	$ 27,690	$ 16,581
Exploratory dry hole costs	29,514	7,518
Leasehold abandonments	49,758	12,395
Other	2,587	3,346
Total exploration and abandonments	$ 109,549	$ 39,840

Our geological and geophysical expense, which primarily consists of the costs of acquiring and processing seismic data, geophysical data and core analysis, primarily relating to our Delaware Basin area, was approximately $27.7 million and

$16.6 million for the years ended December 31, 2013 and 2012, respectively. The increase in 2013 as compared to 2012 is due to our increased drilling and exploration activity in the Delaware Basin area.

During the fourth quarter of 2013, we completed our assessment of our activity on our northern Midland Basin acreage position. Our initial wells on this acreage were uneconomic. We have no further plans to invest in this position. Accordingly, we recognized $14.8 million in exploratory dry hole costs and $34.9 million in leasehold abandonments in 2013.

Our exploratory dry hole costs during the year ended December 31, 2013 were primarily related to (i) partial expensing of unsuccessful horizontal laterals on two wells in the Delaware Basin, (ii) an unsuccessful vertical well in the New Mexico Shelf area that was testing the eastern boundaries of the area, (iii) partial expensing of unsuccessful horizontal laterals in the New Mexico Shelf area and (iv) the northern Midland Basin wells (noted above). Our exploratory dry hole costs during the year ended December 31, 2012 were primarily related to (i) expensing an unsuccessful lateral on a horizontal well due to mechanical issues in the Delaware Basin area, (ii) expensing a dry hole that logged no pay in the Lower Abo formation in the New Mexico Shelf area and (iii) expensing the costs of drilling a well that experienced mechanical issues in the Texas Permian area.

For the year ended December 31, 2013, we recorded approximately $49.8 million of leasehold abandonments, which related to (i) abandonment of the northern Midland Basin acreage position, (ii) expiration of non-prospective acreage in the Delaware Basin area and (iii) abandonment of non-core prospects in the New Mexico Shelf and Texas Permian areas. For the year ended December 31, 2012, we recorded approximately $12.4 million of leasehold abandonments, which related to non-core prospects in our New Mexico Shelf area.

Depreciation, depletion and amortization expense. The following table provides components of our depreciation, depletion and amortization expense for the years ended December 31, 2013 and 2012:

	Years Ended December 31,			
	2013		2012	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
Depletion of proved oil and natural gas properties	$ 755,952	$ 22.48	$ 561,291	$ 20.07
Depreciation of other property and equipment	15,195	0.45	12,376	0.44
Amortization of intangible asset - operating rights	1,461	0.04	1,461	0.05
Total depletion, depreciation and amortization	$ 772,608	$ 22.97	$ 575,128	$ 20.56
Oil price used to estimate proved oil reserves at period end	$ 93.42		$ 91.21	
Natural gas price used to estimate proved natural gas reserves at period end	$ 3.67		$ 2.76	

Depletion of proved oil and natural gas properties was $756.0 million ($22.48 per Boe) for the year ended December 31, 2013, an increase of $194.7 million (35 percent) from $561.3 million ($20.07 per Boe) for the year ended December 31, 2012. The increase in depletion expense was primarily due to (i) increased production associated with new wells that were successfully drilled and completed in 2012 and 2013, (ii) increased production associated with our acquisitions in 2012 and (iii) higher depletion rates. The increase in depletion expense per Boe was primarily due (i) drilling deeper, higher-cost wells in less proven areas and (ii) increasing production in our newer asset areas, such as the Delaware Basin, where we have a higher depletion rate than our legacy assets, such as the New Mexico Shelf.

More of our drilling capital is spent drilling higher-cost horizontal wells, much of which is in areas that have not had significant drilling activity or historically been developed vertically. Generally, when transitioning to a horizontal program, (i) well costs are higher as efficiencies from optimization of drilling and completion methodologies have yet to be realized and (ii) our ability to record proved reserves is limited under the rules associated with recognizing proved reserves, in part due to the limited amount of horizontal wells in the area and the lack of historical well production performance. As a result of these factors, the change in our production amongst our assets, discussed above, and our significant horizontal drilling activities in the Delaware Basin, we have seen increases in our overall depletion rate over the past year to $22.48 per Boe for the year ended December 31, 2013 as compared to $20.07 per Boe for the year ended December 31, 2012.

The increase in depreciation expense was primarily associated with our increase in depreciation of other property and equipment related to buildings and other items as a result of our increased number of employees.

Impairment of long-lived assets. We periodically review our long-lived assets to be held and used, including proved oil and natural gas properties accounted for under the successful efforts method of accounting. Due primarily to a decrease in our estimated future cash flows related to management's outlook of future commodity prices and costs, we recognized a non-cash charge against earnings of $65.4 million during the second quarter of 2013, which was primarily attributable to non-core natural gas related properties in our New Mexico Shelf area. We did not recognize any impairment charges for the year ended December 31, 2012.

General and administrative expenses. The following table provides components of our general and administrative expenses for the years ended December 31, 2013 and 2012:

	Years Ended December 31,			
	2013		2012	
(in thousands, except per unit amounts)	**Amount**	**Per Boe**	**Amount**	**Per Boe**
General and administrative expenses	$ 153,199	$ 4.55	$ 118,256	$ 4.23
Non-cash stock-based compensation	35,078	1.04	29,872	1.07
Less: Third-party operating fee reimbursements	(18,462)	(0.55)	(14,332)	(0.51)
Total general and administrative expenses	$ 169,815	$ 5.04	$ 133,796	$ 4.79

General and administrative expenses were approximately $169.8 million ($5.04 per Boe) for the year ended December 31, 2013, an increase of $36.0 million (27 percent) from $133.8 million ($4.79 per Boe) for the year ended December 31, 2012. The increase in general and administrative expenses and non-cash stock-based compensation was primarily due to (a) a charge in 2013 to adjust our bonus accrual for services related to 2012 of approximately $5.2 million and (b) an increase in salary and the number of employees and related personnel expenses to handle our increased activities of approximately $30.1 million, which includes a $7.5 million increase related to non-cash stock-based compensation, both from (i) increased drilling and exploration activities and (ii) our acquisitions in 2012; partially offset by an approximate $2.3 million net benefit to stock-based compensation related to forfeitures and modifications of stock-based awards associated with two of our former officers in 2013. Additionally, the increase in third-party operating fee reimbursements of $4.1 million, which is due to more wells operated as a result of continued drilling activity, offset overall general and administrative expenses. The increase in overall general and administrative expenses per Boe of $0.25 was primarily due to the factors discussed above, partially offset by (i) increased production from our wells successfully drilled and completed in 2012 and 2013, (ii) increased production from our acquisitions in 2012 and (iii) increased third-party operating fee reimbursements.

As the operator of certain oil and natural gas properties in which we own an interest, we earn overhead reimbursements during the drilling and production phases of the property. We earned reimbursements of $18.5 million and $14.3 million during the years ended December 31, 2013 and 2012, respectively. This reimbursement is reflected as a reduction of general and administrative expenses in the consolidated statements of operations. The increase in third-party operating fee reimbursements was primarily comprised of approximately $1.3 million attributable to the wells acquired in the Three Rivers Acquisition, with the remaining increase primarily due to increased reimbursements attributable to more wells operated as a result of continued drilling activity period over period.

(Gain) loss on derivatives not designated as hedges. The following table sets forth the gain (loss) on derivatives not designated as hedges for the years ended December 31, 2013 and 2012:

(in thousands)		**Years Ended December 31, 2013**		**2012**
Gain (loss) on derivatives not designated as hedges:				
Oil derivatives	$	(133,890)	$	127,293
Natural gas derivatives		10,238		150
Total	$	(123,652)	$	127,443

The following table represents the Company's cash receipts from (payments on) derivatives not designated as hedges for the years ended December 31, 2013 and 2012:

(in thousands)		**Years Ended December 31, 2013**		**2012**
Cash receipts from (payments on) derivatives not designated as hedges:				
Oil derivatives	$	(41,616)	$	22,411
Natural gas derivatives		9,275		1,125
Total	$	(32,341)	$	23,536

Our earnings are affected by the changes in value of our derivatives portfolio between periods and the related cash settlements of those derivatives, which can be volatile. To the extent the future commodity price outlook declines between measurement periods, we will have mark-to-market gains, and to the extent future commodity price outlook increases between measurement periods, we will have mark-to-market losses.

Interest expense. The following table sets forth interest expense, weighted average interest rates and weighted average debt balances for the years ended December 31, 2013 and 2012:

(dollars in thousands)	**Years Ended December 31, 2013**	**2012**

Interest expense	$	218,581	$	182,705
Weighted average interest rate - credit facility		2.3%		2.3%
Weighted average interest rate - senior notes		6.1%		6.6%
Total weighted average interest rate		5.7%		5.6%
Weighted average credit facility balance	$	327,488	$	694,984
Weighted average senior notes balance		3,117,222		2,238,611
Total weighted average debt balance	$	3,444,710	$	2,933,595

The increase in weighted average debt balance during the year ended December 31, 2013 as compared to the corresponding period in 2012 was due primarily to (i) borrowings associated with our acquisitions in 2012 partially offset by our asset divestiture in late 2012 and (ii) capital expenditures in excess of our cash flows. The increase in interest expense was due to an overall increase in the weighted average balance of debt and a slightly increased weighted average interest rate due to a higher percentage of our debt outstanding as senior notes which carry a higher interest rate than our credit facility.

Income tax provisions. We recorded an income tax expense of $118.2 million and $251.0 million for the years ended December 31, 2013 and 2012, respectively. The effective income tax rate for the years ended December 31, 2013 and 2012 was 33.1 percent and 38.1 percent, respectively.

We recorded a $21.9 million income tax benefit in the fourth quarter of 2013 due to a decrease in our estimated overall state tax rate utilized to record our net deferred tax liability. During 2013, the state of New Mexico passed legislation to phase in a tax rate reduction over the next five years from 7.6 percent in 2013 to 5.9 percent in 2018. Additionally, we continuously evaluate the state apportionment, and based on our current forecast, along with the New Mexico rate declines, we have revised our state rate. Excluding the effect of the New Mexico state rate reduction, our effective rate would have been 39.2 percent in 2013, which would approximate a more "normalized" effective income tax rate.

Income from discontinued operations, net of tax. In December 2012, we closed the sale of certain of our non-core assets for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million. As a result of post-closing adjustments during the year ended December 31, 2013, we made a positive adjustment to gain (loss) on disposition of assets of approximately $19.6 million. We recognized income from discontinued operations of $12.1 million and $23.5 million for the years ended December 31, 2013 and 2012, respectively.

The results of operations of these assets are reported as discontinued operations in the accompanying consolidated statements of operations, and are described in more detail in Note 13 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Capital Commitments, Capital Resources and Liquidity

Capital commitments. Our primary needs for cash are development, exploration and acquisition of oil and natural gas assets, payment of contractual obligations and working capital obligations. Funding for these cash needs may be provided by any combination of internally-generated cash flow, financing under our credit facility, proceeds from the disposition of assets or alternative financing sources, as discussed in "— Capital resources" below.

Oil and natural gas properties. Our costs incurred on oil and natural gas properties, excluding acquisitions and asset retirement obligations, during the years ended December 31, 2014, 2013 and 2012 totaled $2.5 billion, $1.8 billion and $1.5 billion respectively. The primary reason for the differences in the costs incurred and cash flow expenditures is the timing of payments. The 2014 expenditures were funded in part from borrowings under our credit facility and proceeds from our May 2014 equity offering.

Delaware Basin midstream agreements. On May 9, 2014, we signed an agreement with an unrelated third party to own 50 percent of a new midstream joint venture. The joint venture was formed to build a crude oil pipeline to gather and transport production in the northern Delaware Basin. We expect the system to be operational in the second half of 2015. We invested $30.1 million in 2014.

Additionally, on May 9, 2014, we entered into a ten year crude petroleum dedication and transportation agreement with the joint venture. Under the terms of the agreement and subject to certain regulatory approvals, we are obligated to deliver oil production to the joint venture from a substantial portion of the properties that we currently operate in the northern Delaware Basin area, as well as oil production from future development of certain of our northern Delaware Basin acreage.

2015 capital budget. In January 2015, we announced our updated 2015 capital budget of approximately $2.0 billion, of which approximately 90 percent of the drilling and completion costs will be dedicated to horizontal drilling. Our 2015 capital program is expected to continue focusing on drilling in the Delaware Basin. The 2015 capital budget, based on our current expectations of commodity prices and cost, will exceed our cash flow. We expect our cash flow and borrowings under our credit facility will be sufficient to fund our budgeted capital expenditure needs during 2015. However, if we experience sustained commodity prices lower than our forecasted pricing without sufficient costs reductions, we may adjust our capital budget to preserve our financial strength.

During 2015, we plan to use our credit facility and may use other financing sources to fund such expenditures in excess of our cash flows. The actual amount and timing of our expenditures may differ materially from our estimates as a result of, among other things, actual drilling results, the timing of expenditures by third parties on projects that we do not operate, the costs of drilling rigs and other services and equipment, regulatory, technological and competitive developments and market conditions. In addition, under certain circumstances, we may consider increasing, decreasing or reallocating our capital spending plans.

Other than the customary purchase of leasehold acreage, our capital budgets are exclusive of acquisitions. We do not have a specific acquisition budget, since the timing and size of acquisitions are difficult to forecast. We evaluate opportunities to purchase or sell oil and natural gas properties in the marketplace and could participate as a buyer or seller of properties at various times. We seek to acquire oil and natural gas properties that provide opportunities for the addition of reserves and production through a combination of development, high-potential exploration and control of operations that will allow us to apply our operating expertise.

Acquisitions. The following table reflects our expenditures for acquisitions of proved and unproved properties for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Property acquisition costs:			
Proved	$ 99,362	$ 11,499	$ 857,836
Unproved (a)	292,363	85,538	441,042
Total property acquisition costs	$ 391,725	$ 97,037	$ 1,298,878

(a) Included in the unproved property acquisition costs above are budgeted leasehold acreage acquisitions of $89.1 million, $67.6 million and $36.1 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Divestitures. In December 2012, we closed the sale of certain non-core assets, a portion of which were acquired in the Three Rivers Acquisition, for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million (included in discontinued operations). For the year ended December 31, 2012 these assets produced an average of 4,937 Boe per day. We estimate that the proved reserves of these assets at closing were approximately 35.3 MMBoe. We used the net proceeds from this divestiture to repay a portion of the outstanding borrowings under our credit facility.

Contractual obligations. We had the following contractual obligations at December 31, 2014:

		Payments Due by Period			
(in thousands)	**Total**	**Less than 1 year**	**1 - 3 years**	**3 - 5 years**	**More than 5 years**
Long-term debt (a)	$ 3,489,500	$ -	$ -	$ 139,500	$ 3,350,000
Cash interest expense on debt (b)	1,569,281	271,297	404,066	402,267	491,651
Asset retirement obligations (c)	119,881	9,146	14,045	4,497	92,193
Employment agreements with officers (d)	7,385	7,385	-	-	-
Purchase obligations (e)	167,174	57,489	45,097	28,683	35,905
Operating lease obligations (f)	36,215	7,245	11,166	8,899	8,905
Total contractual obligations	$ 5,389,436	$ 352,562	$ 474,374	$ 583,846	$ 3,978,654

(a) See Note 8 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for information regarding future interest payment obligations on our long-term debt. The amounts included in the table above represent principal maturities only.

(b) Cash interest expense on our senior notes is estimated assuming no principal repayment until their maturity dates. Cash interest expense on our credit facility is estimated assuming (i) a principal balance outstanding equal to the balance at December 31, 2014 of $139.5 million with no principal repayment until the instrument due date of May 9, 2019 and (ii) a fixed interest rate of 2.0 percent, which was our interest rate at December 31, 2014. Also included in the “Less than 1 year” column is accrued interest at December 31, 2014 of approximately $69.3 million.

(c) Amounts represent costs related to expected oil and natural gas property abandonments related to proved reserves by period, net of any future accretion.

(d) Represents amounts of cash compensation we are obligated to pay to our officers under employment agreements assuming such employees continue to serve the entire term of their employment agreement and their cash compensation is not adjusted.

(e) Relates to purchase agreements we have entered into including daywork drilling contracts, water commitment agreements, throughput volume delivery commitments and power commitments.

(f) We lease vehicles, equipment and office facilities under non-cancellable operating leases.

Off-balance sheet arrangements. Currently, we do not have any material off-balance sheet arrangements.

Capital resources. Our primary sources of liquidity have been cash flows generated from operating activities (including the cash settlements received from (paid on) derivatives not designated as hedges presented in our investing activities) and borrowings under our credit facility. Based on current commodity prices and capital costs, we believe our 2015 capital budget, excluding acquisitions, will exceed our cash flow, and we plan to fund the difference with borrowings under our credit facility or we may use other financing sources. We believe that we have adequate availability under our credit facility to fund any cash flow deficits, though we could reduce our capital spending program to remain substantially within our cash flow.

The following table summarizes our net increase (decrease) in cash and cash equivalents for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Net cash provided by operating activities	$ 1,673,787	$ 1,362,020	$ 1,237,478
Net cash used in investing activities	(2,545,996)	(1,896,794)	(2,240,444)
Net cash provided by financing activities	872,209	531,915	1,005,504
Net increase (decrease) in cash and cash equivalents	$ -	$ (2,859)	$ 2,538

Cash flow from operating activities. The increase in operating cash flows during the year ended December 31, 2014 as compared to 2013 was primarily due to (i) an increase in oil and natural gas revenues of approximately $340.2 million and (ii) approximately $43.5 million of negative variances in operating assets and liabilities compared to $83.6 million of negative variances in operating assets and liabilities in 2013, partially offset by cash increases in oil and natural gas production costs of approximately $——————————————————82.9 million.

The increase in operating cash flows during the year ended December 31, 2013 as compared to 2012 was primarily due to increases in our oil and natural gas revenues of approximately $500.1 million; partially offset by (i) cash increases in oil and natural gas production costs of approximately $111.7 million, (ii) cash increases in general and administration expense and interest expense of approximately $30.8 million and $36.4 million, respectively, and (iii) approximately $83.6 million of negative variances in operating assets and liabilities.

Cash flow used in investing activities. During the years ended December 31, 2014, 2013 and 2012, we invested $2.6 billion, $1.9 billion and $2.7 billion, respectively, for capital expenditures on oil and natural gas properties and acquisitions. The primary reason for the differences in the costs incurred and cash flow expenditures is the timing of payments. The 2014, 2013 and 2012 expenditures were funded in part from borrowings under our credit facility and our equity offering in 2014.

Cash flows used in investing activities were increased during the year ended December 31, 2014 as compared to 2013, primarily due to (i) the increase in amounts invested in oil and natural gas properties during 2014 and 2013 discussed above, (ii) contributions to our equity method investment of $30.1 million during 2014 and (iii) $15.2 million of proceeds from the dispositions of assets during 2013 compared to $1.3 million of proceeds from the dispositions of assets during 2014, partially offset by $72.0 million of receipts from derivatives not designated as hedges during 2014 compared to payments of $32.3 million during 2013. Cash flows used in investing activities were lower during the year ended December 31, 2013 as compared to 2012, primarily due to our Three Rivers Acquisition in 2012 partially offset by (i) an increase in our exploration and development expenditures in 2013 and (ii) a $477.3 million decrease in proceeds from the disposition of assets related to the divestiture of non-core assets in 2012.

Cash flow from financing activities. Below is a description of our financing activities. During 2014, 2013 and 2012 we completed the following significant capital markets activities:

- In May 2014, we issued in a secondary public offering 7.5 million shares of our common stock at $129.00 per share, and we received net proceeds of approximately $932.0 million. We used a portion of the net proceeds from this offering to repay all outstanding borrowings under our credit facility and used the remainder for general corporate purposes, including funding our drilling program and capital commitments associated with the midstream joint venture. See Note 8 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our debt balance at December 31, 2014.

- In June 2013, we issued $850 million in aggregate principal amount of 5.5% senior notes due 2023 at 103.75 percent of par, for which we received net proceeds of approximately $867.8 million. We used a portion of the net proceeds from the offering to fund the tender offer and redemption of the 8.625% Notes at a price of 106.922 percent of the unpaid principal amount. The remaining proceeds were used to pay down amounts outstanding on the credit facility.

- In August 2012, we issued $700 million in aggregate principal amount of 5.5% senior notes due 2023 at par, for which we received net proceeds of approximately $688.6 million. We used the net proceeds to repay a portion of the borrowings under our credit facility.

- In March 2012, we issued $600 million in aggregate principal amount of 5.5% senior notes due 2022 at par, for which we received net proceeds of approximately $590.0 million. We used the net proceeds to repay a portion of the borrowings under our credit facility.

Our credit facility has a maturity date of May 9, 2019. Our borrowing base is $3.25 billion until the next scheduled borrowing base redetermination in May 2015, and commitments from our bank group total $2.5 billion. Between scheduled borrowing base redeterminations, the Company and the lenders (requiring a 66 2/3 percent vote), may each request one special redetermination. At December 31, 2014 we had unused commitments of approximately $2.4 billion based on bank commitments of $2.5 billion. Based on our current ratio as defined in our credit facility as part of our financial covenants, at December 31, 2014, our additional borrowings would be limited to approximately $1.6 billion.

Advances on our credit facility bear interest, at our option, based on (i) the prime rate of JPMorgan Chase Bank ("JPM Prime Rate") (3.25 percent at December 31, 2014) or (ii) a Eurodollar rate (substantially equal to the LIBOR). The credit facility's interest rates of Eurodollar rate advances and JPM Prime Rate advances varied, with interest margins ranging from 125 to 225 basis points and 25 to 125 basis points, respectively, per annum depending on the debt balance outstanding on our credit facility. Under our current credit facility, we pay commitment fees on the unused portion of the available commitment ranging from 30 to 37.5 basis points per annum, depending on utilization of the borrowing base.

In conducting our business, we may utilize various financing sources, including the issuance of (i) fixed and floating rate debt, (ii) convertible securities, (iii) preferred stock, (iv) common stock and (v) other securities. Over the last three years, we have demonstrated our use of capital markets by issuing senior unsecured debt and common stock. There are no assurances that we can access capital markets to obtain additional funding, if needed, and at what cost and terms. We may also sell assets and issue securities in exchange for oil and natural gas assets or interests in oil and natural gas companies. Additional securities may be of a class senior to common stock with respect to such matters as dividends and liquidation rights and may also have other rights and preferences as determined from time-to-time by our board of directors. Utilization of some of these financing sources may require approval from the lenders under our credit facility.

Liquidity. Our principal sources of liquidity are cash on hand and available borrowing capacity under our credit facility. At December 31, 2014, we had approximately $21,000 of cash on hand.

At December 31, 2014, the commitments under our credit facility were $2.5 billion, which provided us with approximately $2.4 billion of unused commitments. Based on our current ratio as defined in our credit facility as part of our financial covenants, at December 31, 2014, our additional borrowings would be limited to approximately $1.6 billion. Upon a redetermination, our $3.25 billion borrowing base could be substantially reduced. There is no assurance that our borrowing base will not be reduced, which could affect our liquidity.

Debt ratings. We receive debt credit ratings from Standard & Poor’s Ratings Group, Inc. (“S&P”) and Moody’s Investors Service, Inc. (“Moody’s”), which are subject to regular reviews. S&P’s corporate rating for us is “BB+” with a stable outlook. Moody's corporate rating for us is "Ba2" with a positive outlook. S&P and Moody's consider many factors in determining our ratings including: production growth opportunities, liquidity, debt levels and asset and reserve mix. A reduction in our debt ratings could negatively affect our ability to obtain additional financing or the interest rate, fees and other terms associated with such additional financing.

Book capitalization and current ratio. Our book capitalization at December 31, 2014 was $8.8 billion, consisting of debt of $3.5 billion and stockholders' equity of $5.3 billion. Our debt to book capitalization was 40 percent and 49 percent at December 31, 2014 and 2013, respectively. Our ratio of current assets to current liabilities was 0.83 to 1.0 at December 31, 2014 as compared to 0.69 to 1.0 at December 31, 2013.

Inflation and changes in prices. Our revenues, the value of our assets, and our ability to obtain bank financing or additional capital on attractive terms have been and will continue to be affected by changes in commodity prices and the costs to produce our reserves. Commodity prices are subject to significant fluctuations that we are unable to control or predict. During the year ended December 31, 2014, we received from continuing operations an average of $83.17 per barrel of oil and $5.39 per Mcf of natural gas before consideration of commodity derivative contracts compared to $91.76 and $87.96 per barrel of oil and $5.08 and $5.06 per Mcf of natural gas in the years ended December 31, 2013 and 2012, respectively. Although certain of our costs are affected by general inflation, inflation does not normally have a significant effect on our business. Historically, higher oil prices led to increased activity in the industry and, consequently, escalated costs. These cost trends put pressure not only on our operating costs, but also on capital costs.

Critical Accounting Policies and Practices

Our historical consolidated financial statements and related notes to consolidated financial statements contain information that is pertinent to our management's discussion and analysis of financial condition and results of operations. Preparation of financial statements in conformity with accounting principles generally accepted in the United States requires that our management make estimates, judgments and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses, and the disclosure of contingent assets and liabilities. However, the accounting principles used by us generally do not change our reported cash flows or liquidity. Interpretation of the existing rules must be done and judgments made on how the specifics of a given rule apply to us.

In management's opinion, the more significant reporting areas impacted by management's judgments and estimates are the choice of accounting method for oil and natural gas activities, oil and natural gas reserve estimation, asset retirement obligations, impairment of long-lived assets, valuation of stock-based compensation, valuation of business combinations, valuation of financial derivative instruments and income taxes. Management's judgments and estimates in these areas are based on information available from both internal and external sources, including engineers, geologists and historical experience in similar matters. Actual results could differ from the estimates as additional information becomes known.

Successful Efforts Method of Accounting

We utilize the successful efforts method of accounting for our oil and natural gas exploration and development activities. Under this method, exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry holes, are charged against income as incurred. Costs of successful wells and related production equipment, undeveloped leases and developmental dry holes are capitalized. Exploratory drilling costs are initially capitalized, but are charged to expense if and when the well is determined not to have found proved reserves. Generally, a gain or loss is recognized when producing properties are sold. This accounting method may yield significantly different results than the full cost method of accounting.

The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory, which will ultimately determine the proper accounting treatment of costs of dry holes. Once a well is drilled, the determination that proved reserves have been discovered may take considerable time, and requires both judgment and application of industry experience. The evaluation of oil and natural gas leasehold acquisition costs included in unproved properties requires management's judgment to estimate the fair value of such properties. Drilling activities in an area by other companies may also effectively condemn our leasehold positions.

Non-producing properties consist of undeveloped leasehold costs and costs associated with the purchase of certain proved undeveloped reserves. Individually significant non-producing properties or projects are periodically assessed for impairment of value by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects.

Depletion of capitalized drilling and development costs of oil and natural gas properties is computed using the unit-of-production method on total estimated proved developed oil and natural gas reserves. Depletion of producing leaseholds is based on the unit-of-production method using our total estimated proved reserves. In arriving at rates under the unit-of-production method, the quantities of recoverable oil and natural gas are established based on estimates made by our geologists and engineers and independent engineers. Service properties, equipment and other assets are depreciated using the straight-line method over estimated useful lives of two to 31 years. Upon sale or retirement of depreciable or depletable property, the cost and related accumulated depreciation and depletion are eliminated from the accounts and the resulting gain or loss is recognized.

Oil and Natural Gas Reserves and Standardized Measure of Discounted Net Future Cash Flows

This report presents estimates of our proved reserves as of December 31, 2014, which have been prepared and presented in accordance with SEC guidelines. The pricing that was used for estimates of our reserves as of December 31, 2014 was based on an unweighted average twelve month WTI posted price of $91.48 per Bbl for oil and a Henry Hub spot natural gas price of $4.35 per MMBtu for natural gas.

Our independent engineers and technical staff prepare the estimates of our oil and natural gas reserves and associated future net cash flows. Even though our independent engineers and technical staff are knowledgeable and follow authoritative guidelines for estimating reserves, they must make a number of subjective assumptions based on professional judgments in developing the reserve estimates. Reserve estimates are updated at least annually and consider recent production levels and other technical information about each field. Periodic revisions to the estimated reserves and future net cash flows may be necessary as a result of a number of factors, including reservoir performance, new drilling, oil and natural gas prices, cost changes, technological advances, new geological or geophysical data, or other economic factors. We cannot predict the amounts or timing of future reserve revisions. If such revisions are significant, they could significantly alter future depletion and result in impairment of long-lived assets that may be material.

It should not be assumed that the Standardized Measure included in this report as of December 31, 2014 is the current market value of our estimated proved reserves. In accordance with SEC requirements, we based the 2014 Standardized Measure on a 12-month average of commodity prices on the first day of the month and prevailing costs on the date of the estimate. Actual future prices and costs may be materially higher or lower than the prices and costs utilized in the estimate. See “Item 1A. Risk Factors” and “Item 2. Properties” for additional information regarding estimates of proved reserves.

Our estimates of proved reserves materially impact depletion expense. If the estimates of proved reserves decline, the rate at which we record depletion expense will increase, reducing future earnings. Such a decline may result from lower commodity prices, which may make it uneconomical to drill for and produce higher cost fields. In addition, a decline in proved reserve estimates may impact the outcome of our assessment of our proved properties for impairment.

Asset Retirement Obligations

There are legal obligations associated with the retirement of long-lived assets that result from the acquisition, construction, development and the normal operation of a long-lived asset. The primary impact of this relates to oil and natural gas wells on which we have a legal obligation to plug and abandon. We record the fair value of a liability for an asset retirement obligation in the period in which it is incurred and, generally, a corresponding increase in the carrying amount of the related long-lived asset. The determination of the fair value of the liability requires us to make numerous judgments and estimates, including judgments and estimates related to future costs to plug and abandon wells, future inflation rates and estimated lives of the related assets. When the judgments used to estimate the initial fair value of the asset retirement obligation change, an adjustment is recorded to both the obligation and the carrying amount of the related long-lived asset.

Impairment of Long-Lived Assets

All of our long-lived assets are monitored for potential impairment when circumstances indicate that the carrying value of an asset may be greater than management's estimates of its future net cash flows, including cash flows from proved reserves and risk-adjusted probable and possible reserves. If the carrying value of the long-lived assets exceeds the sum of estimated undiscounted future net cash flows, an impairment loss is recognized for the difference between the estimated fair value and the carrying value of the assets. The evaluations involve a significant amount of judgment since the results are based on estimated future events, such as future sales prices for oil and natural gas, future costs to produce these products, estimates of future oil and natural gas reserves to be recovered and the timing thereof, the economic and regulatory climates and other factors. The need to test an asset for impairment may result from significant declines in sales prices or downward revisions in estimated quantities of oil and natural gas reserves. Any assets held for sale are reviewed for impairment when we approve the plan to sell. Estimates of anticipated sales prices are highly judgmental and subject to material revision in future periods. Because of the uncertainty inherent in these factors, we cannot predict when or if future impairment charges will be recorded.

Valuation of Stock-Based Compensation

In accordance with GAAP, we calculate the fair value of stock-based compensation using various valuation methods. The valuation methods require the use of estimates to derive the inputs necessary to determine fair value. We utilize (a) the Black-Scholes option pricing model to measure the fair value of stock options, (b) the average of the high and low stock price on the date of grant for the fair value of restricted stock awards and (c) the Monte Carlo simulation method for the fair value of performance unit awards. The significant assumptions used in these models include expected volatility, expected term, risk-free interest rate, forfeiture rate, and the probability of meeting performance targets. Each of these valuation methods were chosen as management believes they give the best estimate of fair value for the respective stock-based awards. See Note 5 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for information regarding our stock-based compensation.

Valuation of Business Combinations

In connection with a purchase business combination, the acquiring company must record assets acquired and liabilities assumed based on fair values as of the acquisition date. Deferred taxes must be recorded for any differences between the assigned values and tax bases of assets and liabilities. Any excess of purchase price over amounts assigned to assets and liabilities is recorded as goodwill. The amount of goodwill recorded in any particular business combination can vary significantly depending upon the value attributed to assets acquired and liabilities assumed.

In estimating the fair values of assets acquired and liabilities assumed, we make various assumptions. The most significant assumptions related to the estimated fair values assigned to proved and unproved oil and natural gas properties. To estimate the fair values of these properties, we utilize estimates of oil and natural gas reserves. We make future price assumptions to apply to the estimated reserves quantities acquired and estimate future operating and development costs to arrive at estimates of future net cash flows. For estimated proved reserves, the future net cash flows were discounted using a market-based weighted average cost of capital rates determined appropriate at the time of the acquisition. The market-based weighted average cost of capital rates are subject to additional project-specific risking factors. To compensate for the inherent risk of estimating and valuing unproved reserves, the discounted future net cash flows of the unproved reserves were reduced by additional risk-weighting factors.

Estimated fair values assigned to assets acquired can have a significant effect on results of operations in the future. A higher fair value assigned to a property results in a higher depletion expense, which results in lower net earnings. Fair values are based on estimates of future commodity prices, reserves quantities, operating expenses and development costs. This increases the likelihood of impairment if future commodity prices or reserves quantities are lower than those originally used to determine fair value or if future operating expenses or development costs are higher than those originally used to determine fair value. Impairment would have no effect on cash flows but would result in a decrease in net income for the period in which the impairment is recorded.

Valuation of Financial Derivative Instruments

In order to reduce commodity price uncertainty and increase cash flow predictability relating to the marketing of our oil and natural gas, we enter into commodity price hedging arrangements with respect to a portion of our expected production. In addition, we have used derivative instruments in connection with acquisitions and certain price-sensitive projects. Management exercises significant judgment in determining the types of instruments to be used, production volumes to be hedged, prices at which to hedge and the counterparties' creditworthiness. All derivative instruments are reflected at fair value in our consolidated balance sheets.

Our open commodity derivative instruments were in a net asset position with a fair value of $752.7 million at December 31, 2014. In order to determine the fair value at the end of each reporting period, we compute discounted cash flows for the duration of each commodity derivative instrument using the terms of the related contract. Inputs consist of published forward commodity price curves as of the date of the estimate. We compare these prices to the price parameters contained in our hedge contracts to determine estimated future cash inflows or outflows. We then discount the cash inflows or outflows using a combination of published LIBOR rates and Eurodollar futures rates. The fair values of our commodity derivative assets and liabilities include a measure of credit risk based on average published yields by credit rating. In addition, for collars, we estimate the option value of the contract floors and ceilings using an option pricing model which takes into account market volatility, market prices and contract parameters.

Changes in the fair values of our commodity derivative instruments have a significant impact on our net income because we follow mark-to-market accounting and recognize all gains and losses on such instruments in earnings in the period in which they occur. For the year ended December 31, 2014, we reported a $890.9 million gain on commodity derivative instruments.

We compare our estimates of the fair values of our commodity derivative instruments with those provided by our counterparties. There have been no significant differences.

Income Taxes

Our provision for income taxes includes both federal and state taxes in jurisdictions in which we operate. We estimate our overall tax rate using a combination of the federal tax rate and a blend of enacted state tax rates. Acquisitions or dispositions of assets could change the apportionment of our state taxes, which would impact our overall tax rate.

Our federal and state income tax returns are generally not prepared or filed before the consolidated financial statements are prepared; therefore, we estimate the tax basis of our assets and liabilities, which are based on numerous judgments and assumptions inherent in the determination of future taxable income, at the end of each period as well as the effects of tax rate changes and tax credits. Adjustments related to these estimates are recorded in our tax provision in the period in which we finalize our income tax returns. Material changes to our tax accruals may occur in the future based on audits, changes in legislation or resolution of pending matters.

Recent Accounting Pronouncements

In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606),” that outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

An entity is required to apply ASU 2014-09 for annual reporting periods beginning after December 15, 2016, and interim periods within those annual periods. An entity can apply ASU 2014-09 using either a full retrospective method, meaning the standard is applied to all of the periods presented, or a modified retrospective method, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. We are evaluating the impact that this new guidance will have on our consolidated financial statements.

In April 2014, the FASB issued ASU No. 2014-08, “Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (Topics 205 and 360),” that raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. Under the revised standard, a discontinued operation is (i) a component of an entity or group of components that has been disposed of by sale, disposed of other than by sale or is classified as held for sale that represents a strategic shift that has or will have a major effect on an entity’s operations and financial results or (ii) an acquired business or nonprofit activity that is classified as held for sale on the date of the acquisition. This update is aimed at reducing the frequency of disposals reported as discontinued operations by focusing on strategic shifts that have or will have a major effect on an entity's operations and financial results.

An entity is required to apply ASU 2014-08 for annual reporting periods beginning on or after December 15, 2014, and interim periods within those annual periods, though earlier adoption is permitted. An entity should provide the disclosures required by this amendment prospectively. We do not expect this guidance to have a significant impact on the consolidated financial statements.

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Item 7A. Quantitative and Qualitative Disclosure About Market Risk

We are exposed to a variety of market risks including credit risk, commodity price risk and interest rate risk. We address these risks through a program of risk management which includes the use of derivative instruments. The following quantitative and qualitative information is provided about financial instruments to which we are a party at December 31, 2014, and from which we may incur future gains or losses from changes in market interest rates or commodity prices and losses from extension of credit. We do not enter into derivative or other financial instruments for speculative or trading purposes.

Hypothetical changes in interest rates and commodity prices chosen for the following estimated sensitivity analysis are considered to be reasonably possible near-term changes generally based on consideration of past fluctuations for each risk category. However, since it is not possible to accurately predict future changes in interest rates and commodity prices, these hypothetical changes may not necessarily be an indicator of probable future fluctuations.

Credit risk. We monitor our risk of loss due to non-performance by counterparties of their contractual obligations. Our principal exposure to credit risk is through the sale of our oil and natural gas production, which we market to energy marketing companies and refineries and to a lesser extent our derivative counterparties. We monitor our exposure to these counterparties primarily by reviewing credit ratings, financial statements and payment history. We extend credit terms based on our evaluation of each counterparty's creditworthiness. Although we have not generally required our counterparties to provide collateral to support their obligation to us, we may, if circumstances dictate, require collateral in the future. In this manner, we reduce credit risk.

We have entered into International Swap Dealers Association Master Agreements ("ISDA Agreements") with each of our derivative counterparties. The terms of the ISDA Agreements provide us and the counterparties with rights of set off upon the occurrence of defined acts of default by either us or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 7 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data" for additional information regarding our derivative activities.

Commodity price risk. We are exposed to market risk as the prices of our commodities are subject to fluctuations resulting from changes in supply and demand. To reduce our exposure to changes in the prices of our commodities, we have entered into, and may in the future enter into, commodity price risk management arrangements for a portion of our oil and natural gas production. The agreements that we have entered into generally have the effect of providing us with a fixed price for a portion of our expected future oil and natural gas production over a fixed period of time. Our commodity price risk management arrangements are recorded at fair value and thus changes to the future commodity prices will have an impact on net income. The following table sets forth the hypothetical impact on the fair value of the commodity price risk management arrangements from an average increase and decrease in the commodity price of $10.00 per Bbl of oil and $1.00 per MMBtu of natural gas from the commodity prices at December 31, 2014:

	Increase of $10 per Bbl and	Decrease of $10 per Bbl and

(in thousands)		$1 per MMBtu		$1 per MMBtu
Gain (loss):				
Oil derivatives	$	(246,647)	$	246,647
Natural gas derivatives		(22,141)		22,141
Total	$	(268,788)	$	268,788

Our commodity price risk management arrangements expose us to risk of non-performance by the counterparty to the agreements. Our exposure to the risk of non-performance is diversified over large, investment grade financial institutions. In addition, we have master netting agreements with the counterparties that allow for offsetting payables against receivables from separate contracts with the same counterparty. At December 31, 2014, the counterparties to our commodity price risk management arrangements include sixteen financial institutions, all of which are secured lenders to our credit facility. Counterparty risk of non-performance is considered when determining the fair value of our commodity price risk management arrangements. The fair value adjustment for non-performance risk was immaterial at both December 31, 2014 and 2013. If at any point a counterparty's financial position deteriorates, such deterioration could have a significant impact on the collectability of that counterparty's related commodity price risk management arrangement asset. See Note 11 of the

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Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for a list of our significant counterparties.

At December 31, 2014, we had (i) oil price swaps that settle on a monthly basis covering future oil production from January 1, 2015 through June 30, 2017 and (ii) oil basis swaps covering our Midland to Cushing basis differential from January 1, 2015 to December 31, 2015. See Note 7 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information on the commodity derivative instruments. The average NYMEX oil price for the year ended December 31, 2014, was $92.94 per Bbl. At February 24, 2015, the NYMEX oil price was $49.28 per Bbl.

At December 31, 2014, we had (i) natural gas price swaps that settle on a monthly basis covering future natural gas production from January 1, 2015 to December 31, 2015 and (ii) natural gas basis swaps covering our basis differeneital between El Paso Permian delivery point and the NYMEX-Henry Hub delivery point from January 1, 2015 to December 31, 2015. See Note 7 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information on our commodity derivative instruments. The average NYMEX natural gas price for the year ended December 31, 2014, was $4.27 per MMBtu. At February 24, 2015, the NYMEX natural gas price was $2.90 per MMBtu.

A decrease in the average NYMEX oil and natural gas prices below those at December 31, 2014 would increase the fair value asset of our commodity derivative contracts from their recorded balance at December 31, 2014. Changes in the recorded fair value of the undesignated commodity derivative contracts are marked to market through earnings as gains or losses. The potential increase in our fair value asset would be recorded in earnings as a gain. However, an increase in the average NYMEX oil and natural gas prices above those at December 31, 2014 would decrease the fair value asset of our commodity derivative contracts from their recorded balance at December 31, 2014. The potential decrease in our fair value asset would be recorded in earnings as a loss. We are currently unable to estimate the effects on the earnings of future periods resulting from changes in the market value of our commodity derivative contracts.

We recorded a gain on derivatives not designated as hedges of $890.9 million for the year ended December 31, 2014, compared to a loss of $123.7 million for the year ended December 31, 2013. The largest factor in the change from 2013 to 2014 primarily related to the decline in commodity future price curves at the respective measurement periods.

The fair value of our derivative instruments is determined based on our valuation models. We did not change our valuation method during the year ended December 31, 2014. During the year ended December 31, 2014, we were party to commodity derivative instruments. See Note 7 of the Notes to Consolidated Financial Statements included in “Item 8. Financial Statements and Supplementary Data” for additional information regarding our derivative instruments. The following table reconciles the changes that occurred in the fair values of our derivative instruments during the year ended December 31, 2014:

(in thousands)		Commodity Derivative Instruments Net Assets (Liabilities) (a)
Fair value of contracts outstanding at December 31, 2013	$	(66,233)
Changes in fair values (b)		890,917
Contract maturities		(71,983)
Fair value of contracts outstanding at December 31, 2014	$	752,701

(a) Represents the fair values of open derivative contracts subject to market risk.
(b) At inception, new derivative contracts entered into by us have no intrinsic value.

Interest rate risk. Our exposure to changes in interest rates relates primarily to debt obligations. We manage our interest rate exposure by limiting our variable-rate debt to a certain percentage of total capitalization and by monitoring the effects of market changes in interest rates. To reduce our exposure to changes in interest rates we have entered into, and may in the future enter into additional interest rate risk management arrangements for a portion of our outstanding debt. The agreements that we have entered into generally have the effect of providing us with a fixed interest rate for a portion of our variable rate debt. We may utilize interest rate derivatives to alter interest rate exposure in an attempt to reduce interest rate expense related to existing debt issues. Interest rate derivatives are used solely to modify interest rate exposure and not to modify the overall leverage of the debt portfolio. We are exposed to changes in interest rates as a result of our credit facility, and the terms of our credit facility require us to pay higher interest rate margins as we utilize a larger percentage of our available commitments.

We had total indebtedness of $139.5 million outstanding under our credit facility at December 31, 2014. The impact of a one percent increase in interest rates on this amount of debt would result in increased annual interest expense of approximately $1.4 million.

Item 8. Financial Statements and Supplementary Data

Our consolidated financial statements and supplementary financial data are included in this report beginning on page F-1.

Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure

We had no changes in, and no disagreements with, our accountants on accounting and financial disclosure.

Item 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. As required by Rule 13a-15(b) of the Exchange Act, we have evaluated, under the supervision and with the participation of our management, including our principal executive officer and principal financial officer, the effectiveness of the design and operation of our disclosure controls and procedures (as defined in Rules 13a-15(e) and 15d-15(e) under the Exchange Act) as of the end of the period covered by this report. Our disclosure controls and procedures are designed to provide reasonable assurance that the information required to be disclosed by us in reports that we file under the Exchange Act is accumulated and communicated to our management, including our principal executive officer and principal financial officer, as appropriate, to allow timely decisions regarding required disclosure and is recorded, processed, summarized and reported within the time periods specified in the rules and forms of the SEC. Based upon the evaluation, our principal executive officer and principal financial officer have concluded that our disclosure controls and procedures were effective at December 31, 2014 at the reasonable assurance level.

Changes in Internal Control over Financial Reporting. There have been no changes in our internal controls over financial reporting (as defined in Rule 13a-15(f) under the Exchange Act) that occurred during our last fiscal quarter that have materially affected or are reasonably likely to materially affect our internal controls over financial reporting.

MANAGEMENT'S REPORT ON INTERNAL CONTROL OVER FINANCIAL REPORTING

The management of the Company is responsible for establishing and maintaining adequate internal control over financial reporting. The Company’s internal control over financial reporting is a process designed under the supervision of the Company’s Chief Executive Officer and Chief Financial Officer to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Company’s financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2014, management assessed the effectiveness of the Company’s internal control over financial reporting based on the criteria for effective internal control over financial reporting established in the 2013 “Internal Control - Integrated Framework,” issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on our assessment and those criteria, management determined that the Company maintained effective internal control over financial reporting at December 31, 2014.

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.

Grant Thornton 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 their report on the effectiveness of the Company’s internal control over financial reporting at December 31, 2014. The report, which expresses an unqualified opinion on the effectiveness of the Company’s internal control over financial reporting at December 31, 2014, is included in this Item under the heading “Report of Independent Registered Public Accounting Firm.”

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

We have audited the internal control over financial reporting of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the "Company") as of December 31, 2014, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Company's 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, the Company maintained, in all material respects, effective internal control over financial reporting as of December 31, 2014, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by COSO.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the consolidated financial statements of the Company as of and for the year ended December 31, 2014, and our report dated February 26, 2015 expressed an unqualified opinion on those financial statements.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 26, 2015

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

Item 10 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

Item 11. Executive Compensation

Item 11 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Stockholder Matters

Equity compensation plans. At December 31, 2014, a total of 7,500,000 shares of common stock were authorized for issuance under our equity compensation plan. In the table below, we describe certain information about these shares and the equity compensation plan which provides for their authorization and issuance. Performance units are included at the maximum potential payout percentage. You can find descriptions of our stock incentive plan under Note 5 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."

Plan category	**(1) Number of securities to be issued upon exercise of outstanding options, warrants and rights**	**(2) Weighted average exercise price of outstanding options**	**(3) Number of securities remaining available for future issuance under equity compensation plans (excluding securities reflected in column (1))**
Equity compensation plan approved by the security holders (a)	798,655	$ 17.49(c)	823,975
Equity compensation plan not approved by the security holders (b)	-	$ -	-
Total	798,655		823,975

(a) 2006 Stock Incentive Plan, as amended and restated. See Note 5 of the Notes to Consolidated Financial Statements included in "Item 8. Financial Statements and Supplementary Data."
(b) None.
(c) Performance unit awards do not have an exercise price and, therefore, have been excluded from the weighted average exercise price calculation in column (2).

The remaining information required by Item 12 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

Item 13. Certain Relationships and Related Transactions, and Director Independence

Item 13 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

Item 14. Principal Accounting Fees and Services

Item 14 will be incorporated by reference pursuant to Regulation 14A under the Exchange Act. We expect to file a definitive proxy statement with the SEC within 120 days after the close of the year ended December 31, 2014.

PART IV

Item 15. Exhibits, Financial Statement Schedules

(a) Listing of Financial Statements

Financial Statements

The following consolidated financial statements are included in “Financial Statements and Supplementary Data”:

Report of Independent Registered Public Accounting Firm

Consolidated Balance Sheets at December 31, 2014 and 2013

Consolidated Statements of Operations for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Stockholders’ Equity for the Years Ended December 31, 2014, 2013 and 2012

Consolidated Statements of Cash Flows for the Years Ended December 31, 2014, 2013 and 2012

Notes to Consolidated Financial Statements

Unaudited Supplementary Data

(b) Exhibits

The exhibits to this report required to be filed pursuant to Item 15(b) are listed below and in the "Index to Exhibits" attached hereto.

(c) Financial Statement Schedules

No financial statement schedules are required to be filed as part of this report or they are inapplicable.

Exhibits

Exhibit Number	Description
1.1	Underwriting Agreement dated May 12, 2014, by and between Concho Resources Inc. and Goldman, Sachs & Co., as representative of the several underwriters listed in Schedule 1 thereto (filed as Exhibit 1.1 to the Company's Current Report on Form 8-K on May 14, 2014, and incorporated herein by reference).
3.1	Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on August 8, 2007, and incorporated herein by reference).
3.2	Second Amended and Restated Bylaws of Concho Resources Inc., as amended November 7, 2012 (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on November 8, 2012, and incorporated herein by reference).
4.1	Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).

Exhibit Number	Description
4.2	Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
4.3	First Supplemental Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.2 to the Company's Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).
4.4	Second Supplemental Indenture, dated November 3, 2010, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.4 to the Post-Effective Amendment to the Company's Registration Statement on Form S-3 on December 7, 2010, and incorporated herein by reference).
4.5	Third Supplemental Indenture, dated December 14, 2010, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on December 14, 2010, and incorporated herein by reference).
4.6	Fourth Supplemental Indenture, dated May 23, 2011, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on May 23, 2011, and incorporated herein by reference).
4.7	Fifth Supplemental Indenture, dated December 12, 2011, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.7 to the Company's Annual Report on Form 10-K on February 24, 2012, and incorporated herein by reference).
4.8	Sixth Supplemental Indenture, dated March 12, 2012, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on March 12, 2012, and incorporated herein by reference).

4.9 Seventh Supplemental Indenture, dated August 17, 2012, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).

4.10 Eighth Supplemental Indenture, dated June 3, 2013, between Concho Resources Inc., the subsidiary guarantors named therein, and Wells Fargo Bank, National Association, as trustee (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on June 6, 2013, and incorporated herein by reference).

4.11 Form of 7.0% Senior Notes due 2021 (included in Exhibit 4.1 to the Company’s Current Report on Form 8-K on December 14, 2010, and incorporated herein by reference).

4.12 Form of 6.5% Senior Notes due 2022 (included in Exhibit 4.1 to the Company’s Current Report on Form 8-K on May 23, 2011, and incorporated herein by reference).

4.13 Form of 5.5% Senior Notes due 2022 (included in Exhibit 4.2 to the Company’s Current Report on Form 8-K on March 12, 2012, and incorporated herein by reference).

4.14 Form of 5.5% Senior Notes due 2023 (included in Exhibit 4.1 to the Company’s Current Report on Form 8-K on August 17, 2012, and incorporated herein by reference).

Exhibit

Number
Description

10.1 ** Separation and Release Agreement dated January 2, 2013, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.2 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).

10.2 ** Form of Performance Unit Award Agreement (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on January 4, 2013, and incorporated herein by reference).

10.3 ** Termination of Consulting Agreement dated August 14, 2013 by and between Concho Resources Inc. and Steven L. Beal (filed as Exhibit 10.2 to the Company's Quarterly Report on Form 10-Q on November 7, 2013 and incorporated herein by reference).

10.4 ** Amended and Restated Concho Resources Inc. 2006 Stock Incentive Plan (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on August 8, 2012, and incorporated herein by reference).

10.5 ** Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).

10.6 ** Form of Restricted Stock Agreement (for officers) (filed as Exhibit 10.11 to the Company's Annual Report on Form 10-K on February 22, 2013, and incorporated herein by reference).

10.7 ** Form of Restricted Stock Agreement (for employees) (filed as Exhibit 10.16 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).

10.8 ** Form of Restricted Stock Agreement (for non-officer employees) (filed as Exhibit 10.36 to the Company's Annual Report on Form 10-K on February 25, 2011, and incorporated herein by reference).

10.9 ** Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K on March 28, 2008, and incorporated herein by reference).

10.10 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

10.11 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed as Exhibit 10.3 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

10.12 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Darin G. Holderness (filed as Exhibit 10.4 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

10.13 ** Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Matthew G. Hyde (filed as Exhibit 10.6 to the Company's Current Report on Form 8-K on December 19, 2008, and incorporated herein by reference).

Exhibit

Number
Description

10.14 ** Employment Agreement dated November 5, 2009, between Concho Resources Inc. and C. William Giraud (filed as Exhibit 10.18 to the Company's Annual Report on Form 10-K on February 26, 2010, and incorporated herein by reference).

10.15 ** Employment Agreement dated March 19, 2014, between Concho Resources Inc. and Jack F. Harper (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on March 24, 2014, and incorporated herein by reference).

10.16 ** Form of First Amendment to Employment Agreement between Concho Resources Inc. and each of Messrs. Leach, Giraud, Holderness, Hyde and Wright (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 6, 2011, and incorporated herein by reference).

10.17 ** Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof (filed as Exhibit 10.23 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).

10.18 ** Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Easter III (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on March 4, 2008, and incorporated herein by reference).

10.19 ** Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyde (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on May 28, 2008, and incorporated herein by reference).

10.20 ** Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holderness (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on August 29, 2008, and incorporated herein by reference).

10.21 ** Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and Mark B. Puckett (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).

10.22 ** Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and C. William Giraud (filed as Exhibit 10.2 to the Company's Current Report on Form 8-K on November 12, 2009, and incorporated herein by reference).

10.23 ** Form of Director and Officer Indemnification Agreement between Concho Resources Inc. and each Messrs. Surma and Harper (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on March 24, 2014, and incorporated herein by reference).

10.24 ** Indemnification Agreement, dated January 10, 2012, between Concho Resources Inc. and Gary A. Merriman (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on January 12, 2012, and incorporated herein by reference).

10.25 Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Company’s Current Report on Form 8-K on August 6, 2008, and incorporated herein by reference).

Exhibit

Number Description

10.26 First Amendment to Amended and Restated Credit Agreement dated as of April 7, 2009, to the Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 4.1 to the Company's Current Report on Form 8-K on April 9, 2009, and incorporated herein by reference).

10.27 Limited Consent and Waiver, dated September 4, 2009, to the Amended and Restated Credit Agreement dated July 31, 2008, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., Bank of America, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on September 22, 2009, and incorporated herein by reference).

10.28 Second Amendment to Amended and Restated Credit Agreement, dated April 26, 2010, by and among Concho Resources Inc., JP Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 4.1 to the Company’s Current Report on Form 8-K on April 29, 2010, and incorporated herein by reference).

10.29 Third Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated June 16, 2010, among Concho Resources Inc. and the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on June 18, 2010, and incorporated herein by reference).

10.30 Fourth Amendment to Amended and Restated Credit Agreement, dated October 7, 2010, among Concho Resources Inc. and the lenders party thereto and JP Morgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.2 to the Company’s Current Report on Form 8-K on October 13, 2010, and incorporated herein by reference).

10.31 Fifth Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated as of December 7, 2010, among Concho Resources Inc. and the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K on December 10, 2010, and incorporated herein by reference).

10.32 Sixth Amendment to Amended and Restated Credit Agreement, dated as of April 25, 2011, among Concho Resources Inc. and the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 27, 2011, and incorporated herein by reference).

10.33 Seventh Amendment to Amended and Restated Credit Agreement, dated as of October 12, 2011, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on October 14, 2011, and incorporated herein by reference).

10.34 Eighth Amendment to Amended and Restated Credit Agreement, dated as of April 12, 2012, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 16, 2012, and incorporated herein by reference).

10.35 Ninth Amendment to Amended and Restated Credit Agreement, dated as of May 31, 2012, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on June 5, 2012, and incorporated herein by reference).

Exhibit Number	Description
10.36	Tenth Amendment to Amended and Restated Credit Agreement, dated as of October 26, 2012, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on October 29, 2012, and incorporated herein by reference).
10.37	Eleventh Amendment to Amended and Restated Credit Agreement, dated as of April 15, 2013, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on April 17, 2013, and incorporated herein by reference).
10.38	Twelfth Amendment to Amended and Restated Credit Agreement, dated as of October 29, 2013, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Current Report on Form 8-K on October 29, 2013, and incorporated herein by reference).
10.39	Second Amended and Restated Credit Agreement, dated as of May 9, 2014, among Concho Resources Inc., the lenders party thereto and JPMorgan Chase Bank, N.A., as Administrative Agent (filed as Exhibit 10.1 to the Company's Quarterly Report on Form 10-Q on May 12, 2014, and incorporated herein by reference).
10.40	Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories thereto (filed as Exhibit 10.12 to the Company's Registration Statement on Form S-1 on April 24, 2007, and incorporated herein by reference).
12.1	(a) Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
21.1	(a) Subsidiaries of Concho Resources Inc.

23.1 (a) Consent of Grant Thornton LLP.

23.2 (a) Consent of Netherland, Sewell & Associates, Inc.

23.3 (a) Consent of Cawley, Gillespie & Associates, Inc.

31.1 (a) Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

31.2 (a) Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.

32.1 (b) Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

32.2 (b) Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.

99.1 (a) Netherland, Sewell & Associates, Inc. Reserve Report.

99.2 (a) Cawley, Gillespie & Associates, Inc. Reserve Report.

101.INS (a) XBRL Instance Document.

101.SCH (a) XBRL Schema Document.

101.CAL (a) XBRL Calculation Linkbase Document.

Exhibit Number		Description
101.DEF	(a)	XBRL Definition Linkbase Document.
101.LAB	(a)	XBRL Labels Linkbase Document.
101.PRE	(a)	XBRL Presentation Linkbase Document.

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or agreement

GLOSSARY OF TERMS

The following terms are used throughout this report:

Bbl One stock tank barrel, of 42 United States gallons liquid volume, used herein in reference to oil, condensate or natural gas liquids.

Boe One barrel of oil equivalent, a standard convention used to express oil and natural gas volumes on a comparable oil equivalent basis. Natural gas equivalents are determined under the relative energy content method by using the ratio of 6.0 Mcf of natural gas to 1.0 Bbl of oil or condensate.

Basin A large natural depression on the earth's surface in which sediments accumulate.

Development wells Wells drilled within the proved area of an oil or natural gas reservoir to the depth of a stratigraphic horizon known to be productive.

Dry hole A well found to be incapable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production would exceed production expenses, taxes and the royalty burden.

Exploratory wells Wells drilled to find and produce oil or natural gas in an unproved area, to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir, or to extend a known reservoir.

Field An area consisting of a single reservoir or multiple reservoirs all grouped on, or related to, the same individual geological structural feature or stratigraphic condition. The field name refers to the surface area, although it may refer to both the surface and the underground productive formations.

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

Gross wells The number of wells in which a working interest is owned.

Horizontal drilling A drilling technique used in certain formations where a well is drilled vertically to a certain depth and then drilled at a high angle to vertical (which can be greater than 90 degrees) in order to stay within a specified interval.

Infill drilling Drilling into the same pool as known producing wells so that oil or natural gas does not have to travel as far through the formation.

LIBOR London Interbank Offered Rate, which is a market rate of interest.

MBbl One thousand barrels of oil, condensate or natural gas liquids.

MBoe One thousand Boe.

Mcf One thousand cubic feet of natural gas.

MMBoe One million Boe.

MMBtu One million British thermal units.

MMcf One million cubic feet of natural gas.

NYMEX The New York Mercantile Exchange.

NYSE The New York Stock Exchange.

Net acres The percentage of total acres an owner owns out of a particular number of acres within a specified tract. For example, an owner who has a 50 percent interest in 100 acres owns 50 net acres.

Net wells The total of fractional working interests owned in gross wells.

PV-10 When used with respect to oil and natural gas reserves, PV-10 means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development and abandonment costs, using prices and costs in effect at the determination date, before income taxes, and without giving effect to non-property-related expenses except for specific general and administrative expenses incurred to operate the properties, discounted to a present value using an annual discount rate of 10 percent. PV-10 is a non-GAAP financial measure.

Productive wells Wells that produce commercial quantities of hydrocarbons, exclusive of their capacity to produce at a reasonable rate of return.

Proved developed reserves Proved developed reserves are reserves of any category that can be expected to be recovered:

(i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well; and

(ii) through installed extraction equipment and infrastructure operational at the time of the reserve estimate if the extraction is by means not involving a well.

Supplemental definitions from the 2007 Petroleum Resources Management System:

Proved Developed Producing Reserves – Developed Producing Reserves are expected to be recovered from completion intervals that are open and producing at the time of the estimate. Improved recovery reserves are considered producing only after the improved recovery project is in operation.

Proved Developed Non-Producing Reserves – Developed Non-Producing Reserves include shut-in and behind-pipe Reserves. Shut-in Reserves are expected to be recovered from (1) completion intervals which are open at the time of the estimate but which have not yet started producing, (2) wells which were shut-in for market conditions or pipeline connections, or (3) wells not capable of production for mechanical reasons. Behind-pipe Reserves are expected to be recovered from zones in existing wells which will require additional completion work or future recompletion prior to start of production. In all cases, production can be initiated or restored with relatively low expenditure compared to the cost of drilling a new well.

Proved reserves Proved reserves are those quantities of oil and natural gas, which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible—from a given date forward, from known reservoirs, and under existing economic conditions, operating methods, and government regulations—prior to the time at which contracts providing the right to operate expire, unless evidence indicates that renewal is reasonably certain, regardless of whether deterministic or probabilistic methods are used for the estimation. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time.

(i) The area of the reservoir considered as proved includes:

(A) the area identified by drilling and limited by fluid contacts, if any, and

(B) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data.

(ii) In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons ("LKH") as seen in a well penetration unless geoscience, engineering, or performance data and reliable technology establishes a lower contact with reasonable certainty.

(iii) Where direct observation from well penetrations has defined a highest known oil ("HKO") elevation and the potential exists for an associated natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering, or performance data and reliable technology establish the higher contact with reasonable certainty.

(iv) Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when:

(A) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and

(B) the project has been approved for development by all necessary parties and entities, including governmental entities.

(v) Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price shall be the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved undeveloped reserves Proved undeveloped oil and natural gas reserves are reserves of any category 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.

(i) Reserves on undrilled acreage shall be limited to those directly offsetting development spacing areas that are reasonably certain of production when drilled, unless evidence using reliable technology exists that establishes reasonable certainty of economic producibility at greater distances.

(ii) Undrilled locations can be classified as having undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless the specific circumstances, justify a longer time.

Recompletion The addition of production from another interval or formation in an existing wellbore.

Reservoir A formation beneath the surface of the earth from which hydrocarbons may be present. Its make-up is sufficiently homogenous to differentiate it from other formations.

Spacing The distance between wells producing from the same reservoir. Spacing is expressed in terms of acres, e.g., 40-acre spacing, and is established by regulatory agencies.

Standardized Measure The present value (discounted at an annual rate of 10 percent) of estimated future net revenues to be generated from the production of proved reserves net of estimated income taxes associated with such net revenues, as determined in accordance with FASB guidelines, without giving effect to non-property related expenses such as indirect general and administrative expenses, and debt service or to depreciation, depletion and amortization. Standardized measure does not give effect to derivative transactions.

Undeveloped acreage Acreage owned or leased on which wells can be drilled or completed to a point that would permit the production of commercial quantities of oil and natural gas regardless of whether such acreage contains proved reserves.

Wellbore The hole drilled by the bit that is equipped for oil or natural gas production on a completed well. Also called a well or borehole.

Working interest The right granted to the lessee of a property to explore for and to produce and own oil, natural gas, or other minerals. The working interest owners bear the exploration, development, and operating costs on either a cash, penalty, or carried basis.

Workover Operations on a producing well to restore or increase production.

WTI West Texas Intermediate - light, sweet blend of oil produced from fields in western Texas.

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.

CONCHO RESOURCES INC.

Date:	February 26, 2015	By	/s/ Timothy A. Leach
			Timothy A. Leach Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)

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.

Signature	Title	Date
/s/ TIMOTHY A. LEACH Timothy A. Leach	Director, Chairman of the Board of Directors, Chief Executive Officer and President (Principal Executive Officer)	February 26, 2015
/s/ DARIN G. HOLDERNESS Darin G. Holderness	Senior Vice President, Chief Financial Officer (Principal Financial Officer)	February 26, 2015
/s/ BRENDA R. SCHROER Brenda R. Schroer	Vice President, Chief Accounting Officer (Principal Accounting Officer)	February 26, 2015
/s/ STEVEN L. BEAL Steven L. Beal	Director	February 26, 2015
/s/ TUCKER S. BRIDWELL Tucker S. Bridwell	Director	February 26, 2015
/s/ WILLIAM H. EASTER III William H. Easter III	Director	February 26, 2015
/s/ GARY A. MERRIMAN Gary A. Merriman	Director	February 26, 2015

/s/ RAY M. POAGE Ray M. Poage	Director	February 26, 2015
/s/ MARK B. PUCKETT Mark B. Puckett	Director	February 26, 2015
/s/ JOHN P. SURMA John P. Surma	Director	February 26, 2015

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REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

Board of Directors and Stockholders

Concho Resources Inc.

We have audited the accompanying consolidated balance sheets of Concho Resources Inc. (a Delaware corporation) and subsidiaries (the “Company”) as of December 31, 2014 and 2013, and the related consolidated statements of operations, stockholders’ equity, and cash flows for each of the three years in the period ended December 31, 2014. 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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of Concho Resources Inc. and subsidiaries as of December 31, 2014 and 2013, and the results of their operations and their cash flows for each of the three years in the period ended December 31, 2014 in conformity with accounting principles generally accepted in the United States of America.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Company's internal control over financial reporting as of December 31, 2014, based on criteria established in the 2013 *Internal Control—Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated February 26, 2015 expressed an unqualified opinion thereon.

/s/ GRANT THORNTON LLP

Tulsa, Oklahoma

February 26, 2015

Concho Resources Inc.
Consolidated Balance Sheets

		December 31,		
(in thousands, except share and per share amounts)		**2014**		**2013**
Assets				
Current assets:				
Cash and cash equivalents	$	21	$	21
Accounts receivable, net of allowance for doubtful accounts:				
Oil and natural gas		250,600		223,790
Joint operations and other		409,665		247,945
Derivative instruments		490,351		590
Deferred income taxes		-		30,069
Prepaid costs and other		37,759		18,460
Total current assets		1,188,396		520,875
Property and equipment:				
Oil and natural gas properties, successful efforts method		13,867,831		11,215,373
Accumulated depletion and depreciation		(3,790,953)		(2,384,108)
Total oil and natural gas properties, net		10,076,878		8,831,265
Other property and equipment, net		129,136		114,783
Total property and equipment, net		10,206,014		8,946,048
Deferred loan costs, net		68,443		73,048
Intangible asset - operating rights, net		27,154		28,615
Inventory		14,435		19,682
Noncurrent derivative instruments		262,349		966
Other assets		33,172		1,930
Total assets	$	11,799,963	$	9,591,164
Liabilities and Stockholders' Equity				
Current liabilities:				
Accounts payable - trade	$	20,380	$	13,936
Bank overdrafts		92,541		36,718
Revenue payable		238,098		177,617
Accrued and prepaid drilling costs		718,300		318,296
Derivative instruments		-		53,701
Deferred income taxes		162,566		-
Other current liabilities		195,308		156,600
Total current liabilities		1,427,193		756,868
Long-term debt		3,517,320		3,630,421
Deferred income taxes		1,438,185		1,334,653
Noncurrent derivative instruments		-		14,088
Asset retirement obligations and other long-term liabilities		136,477		97,185
Commitments and contingencies (Note 9)				
Stockholders' equity:				
Common stock, $0.001 par value; 300,000,000 authorized; 113,264,918 and 105,222,765 shares issued at December 31, 2014 and 2013, respectively		113		105
Additional paid-in capital		3,027,412		2,027,162

Retained earnings		2,279,741		1,741,566
Treasury stock, at cost; 260,124 and 127,305 shares at December 31, 2014 and 2013, respectively		(26,478)		(10,884)
Total stockholders' equity		5,280,788		3,757,949
Total liabilities and stockholders' equity	$	11,799,963	$	9,591,164

The accompanying notes are an integral part of these consolidated financial statements.

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(in thousands, except per share amounts)

Operating revenues:
Oil sales
Natural gas sales

Operating costs and expenses:
Oil and natural gas production
Exploration and abandonments
Depreciation, depletion and amortization
Accretion of discount on asset retirement obligations
Impairments of long-lived assets
General and administrative (including non-cash stock-based compensation of $47,130,

(Gain) loss on derivatives not designated as hedges

Income from operations
Other income (expense):
Interest expense
Loss on extinguishment of debt
Other, net

Income from continuing operations before income taxes
Income tax expense
Income from continuing operations
Income from discontinued operations, net of tax
Net income
Basic earnings per share:
Income from continuing operations
Income from discontinued operations, net of tax

Diluted earnings per share:
Income from continuing operations
Income from discontinued operations, net of tax

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc.
Consolidated Statements of Stockholders' Equity

(in thousands)	Common Stock Issued Shares	Common Stock Issued Amount	Additional Paid-in Capital	Retained Earnings	Treasury Stock Shares	Treasury Stock Amount	Total Stockholders' Equity
BALANCE AT JANUARY 1, 2012	103,756	$ 104	$ 1,925,757	$ 1,058,874	56	$ (3,996)	$ 2,980,739
Net income	-	-	-	431,689	-	-	431,689
Stock options exercised	500	1	8,122	-	-	-	8,123
Grants of restricted stock	471	-	-	-	-	-	-
Cancellation of restricted stock	(59)	-	-	-	-	-	-
Stock-based compensation	-	-	29,872	-	-	-	29,872
Excess tax benefits related to stock-based compensation	-	-	18,963	-	-	-	18,963
Purchase of treasury stock	-	-	-	-	31	(3,190)	(3,190)
BALANCE AT DECEMBER 31, 2012	104,668	105	1,982,714	1,490,563	87	(7,186)	3,466,196
Net income	-	-	-	251,003	-	-	251,003
Stock options exercised	174	-	3,223	-	-	-	3,223
Grants of restricted stock	499	-	-	-	-	-	-
Cancellation of restricted stock	(118)	-	-	-	-	-	-
Stock-based compensation	-	-	35,078	-	-	-	35,078
Excess tax benefits related to stock-based compensation	-	-	6,147	-	-	-	6,147
Purchase of treasury stock	-	-	-	-	40	(3,698)	(3,698)
BALANCE AT DECEMBER 31, 2013	105,223	105	2,027,162	1,741,566	127	(10,884)	3,757,949
Net income	-	-	-	538,175	-	-	538,175
Issuance of common stock	7,475	7	931,982	-	-	-	931,989
Stock options exercised	208	1	4,658	-	-	-	4,659
	448	-	-	-	-	-	-

Grants of restricted stock							
Cancellation of restricted stock	(89)	-	-	-	-	-	-
Stock-based compensation	-	-	47,130	-	-	-	47,130
Excess tax benefits related to stock-based compensation	-	-	16,480	-	-	-	16,480
Purchase of treasury stock	-	-	-	-	133	(15,594)	(15,594)
BALANCE AT DECEMBER 31, 2014	113,265	$ 113	$ 3,027,412	$ 2,279,741	260	$ (26,478)	$ 5,280,788

The accompanying notes are an integral part of these consolidated financial statements.

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Concho Resources Inc.
Consolidated Statements of Cash Flows

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
CASH FLOWS FROM OPERATING ACTIVITIES:			
Net income	$ 538,175	$ 251,003	$ 431,689
Adjustments to reconcile net income to net cash provided by operating activities:			
Depreciation, depletion and amortization	979,740	772,608	575,128
Accretion of discount on asset retirement obligations	7,072	6,047	4,187
Impairments of long-lived assets	447,151	65,375	-
Exploration and abandonments, including dry holes	265,064	80,714	19,913
Non-cash compensation expense	47,130	35,078	29,872
Deferred income taxes	296,167	102,427	241,819
Loss on disposition of assets, net	9,308	1,268	372
(Gain) loss on derivatives not designated as hedges	(890,917)	123,652	(127,443)
Discontinued operations	-	(12,250)	49,011
Other non-cash items	18,379	19,720	12,420
Changes in operating assets and liabilities, net of acquisitions and dispositions:			
Accounts receivable	(104,988)	(40,009)	(23,091)
Prepaid costs and other	(23,628)	4,945	(8,200)
Inventory	2,441	509	(1,587)
Accounts payable	1,566	(18,469)	4,165
Revenue payable	60,481	28,593	16,012
Other current liabilities	20,646	(59,191)	13,211
Net cash provided by operating activities	1,673,787	1,362,020	1,237,478
CASH FLOWS FROM INVESTING ACTIVITIES:			
Capital expenditures on oil and natural gas properties	(2,554,914)	(1,850,992)	(2,717,283)
Additions to other property and equipment	(34,320)	(28,678)	(56,588)
Proceeds from the disposition of assets	1,305	15,217	492,497
Contributions to equity method investment	(30,050)	-	-
Funds held in escrow	-	-	17,394
Settlements received from (paid on) derivatives not designated as hedges	71,983	(32,341)	23,536
Net cash used in investing activities	(2,545,996)	(1,896,794)	(2,240,444)
CASH FLOWS FROM FINANCING ACTIVITIES:			
Proceeds from issuance of debt	2,081,000	3,257,575	4,262,000
Payments of debt	(2,191,500)	(2,729,700)	(3,241,500)
Exercise of stock options	4,659	3,223	8,123
Excess tax benefit from stock-based compensation	16,480	6,147	18,963
Net proceeds from issuance of common stock	931,989	-	-
Payments for loan costs	(10,648)	(14,075)	(23,926)
Purchase of treasury stock	(15,594)	(3,698)	(3,190)
Bank overdrafts	55,823	12,443	(14,966)
Net cash provided by financing activities	872,209	531,915	1,005,504
Net increase (decrease) in cash and cash equivalents	-	(2,859)	2,538

Cash and cash equivalents at beginning of period		21		2,880		342
Cash and cash equivalents at end of period	$	21	$	21	$	2,880
SUPPLEMENTAL CASH FLOWS:						
Cash paid for interest	$	211,342	$	200,961	$	158,715
Cash paid for income taxes	$	27,844	$	21,376	$	19,674

The accompanying notes are an integral part of these consolidated financial statements.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2014, 2013 and 2012

Note 1. ***Organization and nature of operations***

Concho Resources Inc. (the "Company") is a Delaware corporation formed on February 22, 2006. The Company's principal business is the acquisition, development and exploration of oil and natural gas properties primarily located in the Permian Basin region of Southeast New Mexico and West Texas.

Note 2. ***Summary of significant accounting policies***

Principles of consolidation. The consolidated financial statements of the Company include the accounts of the Company and its 100 percent owned subsidiaries. In addition, from time to time, a third-party has formed entities to effectuate a tax-free exchange of assets for the Company. The Company has 100 percent control over the decisions of the entities, but has no direct ownership. The third-party conveys ownership to the Company upon completion of the tax-free exchange process. The Company consolidates the financial statements of these entities. All material intercompany balances and transactions have been eliminated.

Discontinued operations. The Company made the following divestiture of assets during the period covered by these consolidated financial statements:

(dollars in millions)

Date divested		December 2012
Net proceeds	$	503.1
Gain on disposition of assets	$	0.9

As a result, the Company has reflected the results of operations of these divested assets as discontinued operations, rather than as a component of continuing operations. See Note 13 for additional information regarding this divestiture and its discontinued operations.

Use of estimates in the preparation of financial statements. Preparation of financial statements in conformity with generally accepted accounting principles in the United States of America ("U.S. GAAP") requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities, the disclosure of contingent assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting periods. Actual results could differ from these estimates. Depletion of oil and natural gas properties is determined using estimates of proved oil and natural gas reserves. There are numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. Similarly, evaluations for impairment of proved and unproved oil and natural gas properties are subject to numerous uncertainties including, among others, estimates of future recoverable reserves and commodity price outlooks. Other significant estimates include, but are not limited to, the asset retirement obligations, fair value of derivative financial instruments, the fair value of business combinations, fair value of stock-based compensation and income taxes.

Cash equivalents. The Company considers all cash on hand, depository accounts held by banks, money market accounts and investments with an original maturity of three months or less to be cash equivalents. The Company's cash and cash equivalents are held in financial institutions in amounts that exceed the insurance limits of the Federal Deposit Insurance Corporation. However, management believes that the Company's counterparty risks are minimal based on the reputation and history of the institutions selected.

Accounts receivable. The Company sells oil and natural gas to various customers and participates with other parties in the drilling, completion and operation of oil and natural gas wells. Joint interest and oil and natural gas sales receivables related to these operations are generally unsecured. The Company determines joint interest operations accounts receivable allowances based on management's assessment of the creditworthiness of the joint interest owners and the Company's ability

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Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2014, 2013 and 2012

to realize the receivables through netting of anticipated future production revenues. Receivables are considered past due if full payment is not received by the contractual due date. Past due accounts are generally written off against the allowance for doubtful accounts only after all collection attempts have been exhausted. The Company had an allowance for doubtful accounts of approximately $0.7 million at both December 31, 2014 and 2013.

Inventory. Inventory consists primarily of tubular goods and other oilfield equipment that the Company plans to utilize in its ongoing exploration and development activities and is carried at the lower of cost or market value, on a weighted average cost basis.

Deferred loan costs. Deferred loan costs are stated at cost, net of amortization, which is computed using the effective interest and straight-line methods. The Company had deferred loan costs of $68.4 million and $73.0 million, net of accumulated amortization of $59.7 million and $48.7 million, at December 31, 2014 and December 31, 2013, respectively.

Oil and natural gas properties. The Company utilizes the successful efforts method of accounting for its oil and natural gas properties. Under this method all costs associated with productive wells and nonproductive development wells are capitalized, while nonproductive exploration costs are expensed. Capitalized acquisition costs relating to proved properties are depleted using the unit-of-production method based on proved reserves. The depletion of capitalized drilling and development costs is based on the unit-of-production method using proved developed reserves. During the years ended December 31, 2014, 2013 and 2012, the Company recognized depletion expense from continuing and discontinued operations of $960.9 million, $756.0 million and $591.3 million, respectively.

The Company generally does not carry the costs of drilling an exploratory well as an asset in its consolidated balance sheets following the completion of drilling unless the exploratory well finds oil and natural gas reserves in an area requiring a major capital expenditure and both of the following conditions are met:

(i) the well has found a sufficient quantity of reserves to justify its completion as a producing well; and

(ii) the Company is making sufficient progress assessing the reserves and the economic and operating viability of the project.

Due to the capital intensive nature and the geographical location of certain projects, it may take the Company longer than one year to evaluate the future potential of the exploration well and economics associated with making a determination on its commercial viability. In these instances, the project's feasibility is not contingent upon price improvements or advances in technology, but rather the Company's ongoing efforts and expenditures related to accurately predicting the hydrocarbon recoverability based on well information, gaining access to other companies' production, transportation or processing facilities and/or getting partner approval to drill additional appraisal wells. These activities are ongoing and being pursued constantly. Consequently, the Company's assessment of suspended exploratory well costs is continuous until a decision can be made that the well has found proved reserves or is noncommercial and is charged to exploration and abandonments expense. See Note 3 for additional information regarding the Company's suspended exploratory well costs.

Proceeds from the sales of individual properties and the capitalized costs of individual properties sold or abandoned are credited and charged, respectively, to accumulated depletion. Generally, no gain or loss is recognized until the entire depletion base is sold. However, gain or loss is recognized from the sale of less than an entire depletion base if the disposition is significant enough to materially impact the depletion rate of the remaining properties in the depletion base. Ordinary maintenance and repair costs are expensed as incurred.

Costs of significant nonproducing properties, wells in the process of being drilled and completed and development projects are excluded from depletion until the related project is completed and proved developed reserves are established or, if unsuccessful, impairment is determined. The Company capitalizes interest, if debt is outstanding, on expenditures for significant development projects until such projects are ready for their intended use. The Company had capitalized interest of $1.4 million during 2014. The Company did not capitalize interest during 2013 or 2012.

The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties,

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2014, 2013 and 2012

whenever events or circumstances indicate that the carrying value of those assets may not be recoverable. An impairment loss is indicated if the sum of the expected future cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by depletion base or by individual well for those wells not constituting part of a depletion base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value (discounted future cash flows) of the properties would be recognized at that time. Estimating future cash flows involves the use of judgments, including estimation of the proved and risk-adjusted unproved oil and natural gas reserve quantities, timing of development and production, expected future commodity prices, capital expenditures and production costs. The Company recognized impairment expense of $447.2 million and $65.4 million during the years ended December 31, 2014 and 2013, respectively, related to its proved oil and natural gas properties. The Company did not recognize impairment expense related to its long-lived assets for the year ended December 31, 2012.

Unproved oil and natural gas properties are each periodically assessed for impairment by considering future drilling plans, the results of exploration activities, commodity price outlooks, planned future sales or expiration of all or a portion of such projects. During the years ended December 31, 2014, 2013 and 2012, the Company recognized expense of $217.3 million, $49.8 million and $12.4 million, respectively, related to abandoned prospects and expiring acreage, which is included in exploration and abandonments expense in the accompanying consolidated statements of operations.

Other property and equipment. Other capital assets include buildings, transportation equipment, computer equipment and software, telecommunications equipment, leasehold improvements and furniture and fixtures. These items are recorded at cost, or fair value if acquired, and are depreciated using the straight-line method based on expected lives of the individual assets or group of assets ranging from two to 31 years. The Company had other capital assets of $129.1 million and $114.8 million, net of accumulated depreciation of $52.5 million and $39.2 million, at December 31, 2014 and December 31, 2013, respectively. During the years ended December 31, 2014, 2013 and 2012, the Company recognized depreciation expense of $17.3 million, $15.2 million and $12.4 million, respectively.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2014, 2013 and 2012

Intangible assets. The Company has capitalized certain operating rights acquired in an acquisition. The gross operating rights, which have no residual value, are amortized over the estimated economic life of 25 years. Impairment will be assessed if indicators of potential impairment exist or when there is a material change in the remaining useful economic life. The following table reflects the gross and net intangible assets at December 31, 2014 and 2013, respectively:

	December 31,	
(in thousands)	**2014**	**2013**
Gross intangible - operating rights	$ 36,557	$ 36,557
Accumulated amortization	(9,403)	(7,942)
Net intangible - operating rights	$ 27,154	$ 28,615

The following table reflects amortization expense from continuing and discontinued operations for the years ended December 31, 2014, 2013 and 2012:

	Years Ending December 31,		
(in thousands)	**2014**	**2013**	**2012**
Amortization expense	$ 1,461	$ 1,461	$ 1,549

The following table reflects the estimated aggregate amortization expense for each of the periods presented below at December 31, 2014:

(in thousands)	
2015	$ 1,461
2016	1,461
2017	1,461
2018	1,461
2019	1,461
Thereafter	19,849
Total	$ 27,154

Equity method investment. The Company owns a 50 percent member interest in a midstream joint venture, Alpha Crude Connector, LLC ("ACC"), to construct a crude oil gathering and transportation system in the northern Delaware Basin. The Company accounts for its investment in ACC under the equity method of accounting for investments in unconsolidated affiliates. The Company's net investment in ACC is $29.5 million at December 31, 2014 and is included in other assets in the Company's consolidated balance sheet. The equity loss for the period since inception is approximately $1.3 million and is included in other expense in the Company's consolidated statement of operations. During 2014, the Company recorded $0.7 million of capitalized interest on the investment in ACC.

Environmental. The Company is subject to extensive federal, state and local environmental laws and regulations. These laws, which are often changing, regulate the discharge of materials into the environment and may require the Company to remove or mitigate the environmental effects of the disposal or release of petroleum or chemical substances at various sites. Environmental expenditures are expensed. Expenditures that relate to an existing condition caused by past operations and that have no future economic benefits are expensed. Liabilities for expenditures of a noncapital nature are recorded when

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2014, 2013 and 2012

environmental assessment and/or remediation is probable and the costs can be reasonably estimated. Such liabilities are generally undiscounted unless the timing of cash payments is fixed and readily determinable. At December 31, 2014 and 2013, the Company has accrued approximately $1.7 million and $2.3 million, respectively, related to environmental liabilities. During the years ended December 31, 2014, 2013 and 2012, the Company recognized environmental charges of $4.0 million, $3.4 million and $4.4 million, respectively.

Derivative instruments. The Company recognizes its derivative instruments, other than any commodity derivative contracts that are designated as normal purchase and normal sale, as either assets or liabilities measured at fair value. The Company netted the fair value of derivative instruments by counterparty in the accompanying consolidated balance sheets where the right of offset exists. The Company did not have any derivatives designated as fair value or cash flow hedges during the years ended December 31, 2014, 2013 or 2012. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company’s consolidated financial statements.

Asset retirement obligations. The Company records the fair value of a liability for an asset retirement obligation in the period in which it is incurred and a corresponding increase in the carrying amount of the related long-lived asset. Subsequently, the asset retirement cost included in the carrying amount of the related asset is allocated to expense through depletion of the asset. Changes in the liability due to passage of time are generally recognized as an increase in the carrying amount of the liability and as corresponding accretion expense.

Treasury stock. Treasury stock purchases are recorded at cost. Upon reissuance, the cost of treasury shares held is reduced by the average purchase price per share of the aggregate treasury shares held.

Revenue recognition. Oil and natural gas revenues are recorded at the time of physical transfer of such products to the purchaser, which for the Company is primarily at the wellhead. The Company follows the sales method of accounting for oil and natural gas sales, recognizing revenues based on the Company’s actual proceeds from the oil and natural gas sold to purchasers.

Oil and natural gas imbalances. Oil and natural gas imbalances are generated on properties for which two or more owners have the right to take production “in-kind” and, in doing so, take more or less than their respective entitled percentage. Imbalances are tracked by well, but the Company does not record any receivable from or payable to the other owners unless the imbalance has reached a level at which it exceeds the remaining reserves in the respective well. If reserves are insufficient to offset the imbalance and the Company is in an overtake position, a liability is recorded for the amount of shortfall in reserves valued at a contract price or the market price in effect at the time the imbalance is generated. If the Company is in an undertake position, a receivable is recorded for an amount that is reasonably expected to be received, not to exceed the current market value of such imbalance. The Company had no significant imbalances at December 31, 2014 or 2013.

General and administrative expense. The Company receives fees for the operation of jointly-owned oil and natural gas properties and records such reimbursements as reductions of general and administrative expense. Such fees from continuing and discontinued operations totaled approximately $23.2 million, $18.5 million and $16.8 million for the years ended December 31, 2014, 2013 and 2012, respectively.

Stock-based compensation. For stock-based compensation awards granted, stock-based compensation expense is being recognized in the Company's financial statements on an accelerated basis over the awards' vesting periods based on their fair values on the dates of grant. The stock-based compensation awards generally vest over a period ranging from one to five years. The Company utilizes (i) the Black-Scholes option pricing model to measure the fair value of stock options, (ii) the average of the grant date’s high and low stock prices for the fair value of restricted stock and (iii) the Monte Carlo simulation method for the fair value of performance unit awards.

Income taxes. The Company recognizes deferred tax assets and liabilities for the future tax consequences attributable to differences between the financial statement carrying amounts of existing assets and liabilities and their respective tax bases.

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2014, 2013 and 2012

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 are expected to be recovered or settled. The effect on deferred tax assets and liabilities of a change in tax rate is recognized in income in the period that includes the enactment date. A valuation allowance is established to reduce deferred tax assets if it is more likely than not that the related tax benefits will not be realized.

The Company evaluates uncertain tax positions for recognition and measurement in the consolidated financial statements. To recognize a tax position, the Company determines whether it is more likely than not that the tax positions will be sustained upon examination, including resolution of any related appeals or litigation, based on the technical merits of the position. A tax position that meets the more likely than not threshold is measured to determine the amount of benefit to be recognized in the consolidated financial statements. The amount of tax benefit recognized with respect to any tax position is measured as the largest amount of benefit that is greater than 50 percent likely of being realized upon settlement. The Company had no material uncertain tax positions that required recognition in the consolidated financial statements at December 31, 2014 and 2013. Any interest or penalties would be recognized as a component of income tax expense.

Recent accounting pronouncements. In May 2014, the FASB issued ASU No. 2014-09, “Revenue from Contracts with Customers (Topic 606),” that outlines a new, single comprehensive model for entities to use in accounting for revenue arising from contracts with customers and supersedes most current revenue recognition guidance, including industry-specific guidance. This new revenue recognition model provides a five-step analysis in determining when and how revenue is recognized. The new model will require revenue recognition to depict the transfer of promised goods or services to customers in an amount that reflects the consideration a company expects to receive in exchange for those goods or services.

An entity is required to apply ASU 2014-09 for annual reporting periods beginning after December 15, 2016, and interim periods within those annual periods. An entity can apply ASU 2014-09 using either a full retrospective method, meaning the standard is applied to all of the periods presented, or a modified retrospective method, meaning the cumulative effect of initially applying the standard is recognized in the most current period presented in the financial statements. The Company is evaluating the impact that this new guidance will have on its consolidated financial statements.

In April 2014, the FASB issued ASU No. 2014-08, “Reporting Discontinued Operations and Disclosures of Disposals of Components of an Entity (Topics 205 and 360),” that raises the threshold for a disposal to qualify as a discontinued operation and requires new disclosures of both discontinued operations and certain other disposals that do not meet the definition of a discontinued operation. Under the revised standard, a discontinued operation is (i) a component of an entity or group of components that has been disposed of by sale, disposed of other than by sale or is classified as held for sale that represents a strategic shift that has or will have a major effect on an entity's operations and financial results or (ii) an acquired business or nonprofit activity that is classified as held for sale on the date of the acquisition. This update is aimed at reducing the frequency of disposals reported as discontinued operations by focusing on strategic shifts that have or will have a major effect on an entity's operations and financial results.

An entity is required to apply ASU 2014-08 for annual reporting periods beginning on or after December 15, 2014, and interim periods within those annual periods, though earlier adoption is permitted. An entity should provide the disclosures required by this amendment prospectively. The Company does not expect this guidance to have a significant impact on the consolidated financial statements.

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Note 3. ***Exploratory well costs***

The Company capitalizes exploratory well costs until a determination is made that the well has either found proved reserves or that it is impaired. The capitalized exploratory well costs are carried in unproved oil and natural gas properties. See Unaudited Supplementary Data for the proved and unproved components of oil and natural gas properties. If the exploratory well is determined to be impaired, the well costs are charged to exploration and abandonments expense in the consolidated statements of operations.

The following table reflects the Company's net capitalized exploratory well activity during each of the years ended December 31, 2014, 2013 and 2012:

(in thousands)	Years Ended December 31, 2014	2013	2012
Beginning capitalized exploratory well costs	$ 144,504	$ 118,806	$ 107,767
Additions to exploratory well costs pending the determination of proved reserves	234,057	130,967	112,529
Reclassifications due to determination of proved reserves	(99,657)	(94,114)	(99,514)
Exploratory well costs charged to expense	(37,247)	(11,155)	(1,976)
Ending capitalized exploratory well costs	$ 241,657	$ 144,504	$ 118,806

The following table provides an aging at December 31, 2014 and 2013 of capitalized exploratory well costs based on the date drilling was completed:

(dollars in thousands)	December 31, 2014	2013
Capitalized exploratory well costs that have been capitalized for a period of one year or less	$ 232,346	$ 122,753
Capitalized exploratory well costs that have been capitalized for a period greater than one year	9,311	21,751
Total capitalized exploratory well costs	$ 241,657	$ 144,504
Number of projects with exploratory well costs that have been capitalized for a period greater than one year	7	10

Projects operated by others. At December 31, 2014, the Company had approximately $6.3 million of suspended well costs greater than one year recorded for five wells that are operated by others and waiting on completion.

Other projects. At December 31, 2014, the Company had approximately $3.0 million of suspended well costs greater than one year recorded for two wells that have encountered technical difficulties that the Company is in the process of redrilling.

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Note 4. ***Asset retirement obligations***

The Company’s asset retirement obligations represent the estimated present value of the estimated cash flows the Company will incur to plug, abandon and remediate its producing properties at the end of their productive lives, in accordance with applicable state laws. Market risk premiums associated with asset retirement obligations are estimated to represent a component of the Company's credit-adjusted risk-free rate that is utilized in the calculations of asset retirement obligations.

The Company’s asset retirement obligation transactions during the years ended December 31, 2014, 2013 and 2012 are summarized in the table below:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Asset retirement obligations, beginning of period	$ 101,593	$ 86,261	$ 59,685
Liabilities incurred from new wells	5,324	6,338	7,729
Liabilities assumed in acquisitions	4,065	593	29,113
Accretion expense for continuing operations	7,072	6,047	4,187
Accretion expense for discontinued operations	-	-	1,004
Disposition of wells	-	-	(24,614)
Liabilities settled upon plugging and abandoning wells	(2,926)	(3,447)	(1,261)
Revision of estimates	4,753	5,801	10,418
Asset retirement obligations, end of period	$ 119,881	$ 101,593	$ 86,261

Note 5. ***Incentive plans***

Defined contribution plan. The Company sponsors a 401(k) defined contribution plan for the benefit of substantially all employees. During the years ended December 31, 2014, 2013 and 2012, the Company matched 100 percent of employee contributions, not to exceed 10 percent of the employee’s annual salary. The Company’s contributions to the plan for the years ended December 31, 2014, 2013 and 2012 were approximately $8.1 million, $6.6 million and $5.3 million, respectively, of which a portion was recoverable from other working interest owners.

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Stock incentive plan. The Company's 2006 Stock Incentive Plan, as amended and restated (the "Plan"), provides for granting stock options, restricted stock awards and performance awards to directors, officers and employees of the Company. A total of 7.5 million shares of common stock have been authorized for issuance under the Plan. At December 31, 2014, the Company had 823,975 awards available for future grant.

Restricted stock awards. All restricted shares are legally issued and outstanding. If an employee terminates employment prior to the restriction lapse date, the awarded shares are forfeited and cancelled and are no longer considered issued and outstanding. A summary of the Company's restricted stock award activity for the years ended December 31, 2014, 2013 and 2012 is presented below:

	Number of Restricted Shares	Weighted Average Grant Date Fair Value Per Share
Restricted stock:		
Outstanding at January 1, 2012	912,013	
Shares granted	470,633	$ 98.31
Shares cancelled / forfeited	(58,727)	
Lapse of restrictions	(251,392)	
Outstanding at December 31, 2012	1,072,527	
Shares granted	498,468	$ 88.19
Shares cancelled / forfeited	(118,472)	
Lapse of restrictions	(236,074)	
Outstanding at December 31, 2013	1,216,449	
Shares granted	448,730	$ 129.12
Shares cancelled / forfeited	(89,401)	
Lapse of restrictions	(484,469)	
Outstanding at December 31, 2014	1,091,309	

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For restricted stock awards granted, stock-based compensation expense is being recognized in the Company's financial statements on an accelerated basis over the awards' vesting periods based on their fair values on the dates of grant. The restricted stock-based compensation awards generally vest over a period ranging from one to five years. The Company utilizes the average of the grant date's high and low stock prices for the fair value of restricted stock.

The following table summarizes information about stock-based compensation for the Company's restricted stock awards activity under the Plan for years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Grant date fair value for awards during the period (a)	$ 57,940	$ 44,947	$ 46,268
Stock-based compensation expense from restricted stock	$ 36,585	$ 30,984	$ 29,685
Income taxes and other information:			
Income tax benefit related to restricted stock	$ 13,672	$ 11,650	$ 11,349
Deductions in current taxable income related to restricted stock vestings	$ 58,908	$ 20,883	$ 23,570

(a) The year ended December 31, 2013 includes the effects of $1 million due to modifications of certain stock-based awards.

Stock option awards. A summary of the Company's stock option award activity under the Plan for the years ended December 31, 2014, 2013 and 2012 is presented below:

	Years Ended December 31,					
	2014		**2013**		**2012**	
	Number of Options	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Exercise Price**	**Number of Options**	**Weighted Average Exercise Price**
Stock options:						

Outstanding at beginning of period	255,537	$	21.50	429,879	$	20.28	930,178	$	18.10
Options exercised	(207,824)	$	22.42	(174,342)	$	18.48	(500,299)	$	16.24
Outstanding at end of period	47,713	$	17.49	255,537	$	21.50	429,879	$	20.28
Vested and exercisable at end of period	47,713	$	17.49	255,537	$	21.50	403,077	$	20.24

The intrinsic value of options exercised during 2014, 2013 and 2012 was approximately $23.2 million, $13.2 million and $39.8 million, respectively, based on the difference between the market price at the exercise date and the option exercise price.

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The following table summarizes information about the Company's vested and exercisable stock options outstanding at December 31, 2014:

Range of Exercise Prices	Number Vested	Weighted Average Remaining Contractual Life		Weighted Average Exercise Price		Intrinsic Value of Options (in thousands)
December 31, 2014:						
Vested and exercisable options:						
$12.00	5,636	0.91 years	$	12.00	$	495
$12.50 - $15.50	15,000	2.62 years	$	12.85		1,304
$20.00 - $23.00	27,077	3.98 years	$	21.20		2,127
	47,713	3.19 years	$	17.49	$	3,926

The following table summarizes information about stock-based compensation for stock options for the years ended December 31, 2014, 2013 and 2012:

(in thousands)		Years Ended December 31, 2014		2013		2012
Stock-based compensation expense from stock options	$	-	$	14	$	187
Income taxes and other information:						
Income tax benefit related to stock options	$	-	$	6	$	72
Deductions in current taxable income related to stock options exercised	$	23,208	$	13,193	$	39,828

Performance unit awards. During the years ended December 31, 2014 and 2013, the Company awarded performance units to its officers under the Plan. The number of shares of common stock that will ultimately be issued will be determined by a combination of (i) comparing the Company's total shareholder return relative to the total shareholder return of a predetermined group of peer companies at the end of the performance period and (ii) the Company's absolute total shareholder return at the end of the performance period. The performance period is 36 months. The grant date fair value was determined using the Monte Carlo simulation method and is being expensed ratably over the performance period. Expected volatilities utilized in the model were estimated using a historical period consistent with the remaining performance period of approximately three years. The risk-free interest rate was based on the United States Treasury rate for a term commensurate with the expected life of the grant.

The Company used the following assumptions to estimate the fair value of performance unit awards granted during the years ended December 31, 2014 and 2013:

	Years Ended December 31,	
	2014	**2013**
Risk-free interest rate	0.76%	0.37%
Range of volatilities	29.2% - 42.2%	31.5% - 45.1%

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The following table summarizes the performance unit activity for the years ended December 31, 2014 and 2013:

	Number of Units (a)		Grant Date Fair Value
Performance units:			
Outstanding at December 31, 2012	-		
Units granted	110,889	$	111.40
Outstanding at December 31, 2013	110,889		
Units granted	139,425	$	139.54
Outstanding at December 31, 2014	250,314		

(a) Reflects the amount of performance units granted. The actual payout of shares will be between zero and 300 percent of the performance units granted depending on the Company's performance at the end of the performance period.

The following table summarizes information about stock-based compensation expense for performance units for the years ended December 31, 2014 and 2013:

	Years Ended December 31,			
(in thousands)		**2014**		**2013**
Grant date fair value for awards during the period	$	19,455	$	12,352
Stock-based compensation expense from performance units	$	10,545	$	4,080
Income tax benefit related to performance units	$	3,941	$	1,560

Future stock-based compensation expense. The following table reflects the future stock-based compensation expense to be recorded for all the stock-based compensation awards that were outstanding at December 31, 2014:

(in thousands)		**Restricted Stock**		**Performance Units**		**Total**
2015	$	30,290	$	10,668	$	40,958

2016		18,819		6,514		25,333
2017		7,066		-		7,066
2018		851		-		851
2019		3		-		3
Total	$	57,029	$	17,182	$	74,211

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Note 6. ***Disclosures about fair value of financial instruments***

The Company uses a valuation framework based upon inputs that market participants use in pricing an asset or liability, which are classified into two categories: observable inputs and unobservable inputs. Observable inputs represent market data obtained from independent sources, whereas unobservable inputs reflect a company's own market assumptions, which are used if observable inputs are not reasonably available without undue cost and effort. These two types of inputs are further prioritized into the following fair value input hierarchy:

Level 1**:** Unadjusted quoted prices in active markets that are accessible at the measurement date for identical, unrestricted assets or liabilities. The Company considers active markets to be those in which transactions for the assets or liabilities occur in sufficient frequency and volume to provide pricing information on an ongoing basis.

Level 2**:** Quoted prices in markets that are not active, or inputs which are observable, either directly or indirectly, for substantially the full term of the asset or liability. This category includes those derivative instruments that the Company values using observable market data. Substantially all of these inputs are observable in the marketplace throughout the full term of the derivative instrument, can be derived from observable data, or supported by observable levels at which transactions are executed in the marketplace. Level 2 instruments primarily include non-exchange traded derivatives such as over-the-counter commodity price swaps, basis swaps, collars and floors, investments and interest rate swaps. The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) current market and contractual prices for the underlying instruments and (iv) volatility factors, as well as other relevant economic measures.

Level 3**:** Measured based on prices or valuation models that require inputs that are both significant to the fair value measurement and less observable from objective sources (*i.e.*, supported by little or no market activity). The Company's valuation models are primarily industry-standard models that consider various inputs including: (i) quoted forward prices for commodities, (ii) time value, (iii) volatility factors and (iv) current market and contractual prices for the underlying instruments, as well as other relevant economic measures.

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Financial Assets and Liabilities Measured at Fair Value

The following table presents the carrying amounts and fair values of the Company's financial instruments at December 31, 2014 and 2013:

(in thousands)	December 31, 2014 Carrying Value	December 31, 2014 Fair Value	December 31, 2013 Carrying Value	December 31, 2013 Fair Value
Assets:				
Derivative instruments	$ 752,700	$ 752,700	$ 1,556	$ 1,556
Liabilities:				
Derivative instruments	$ -	$ -	$ 67,789	$ 67,789
Credit facility	$ 139,500	$ 131,068	$ 250,000	$ 250,770
7.0% senior notes due 2021	$ 600,000	$ 625,500	$ 600,000	$ 660,000
6.5% senior notes due 2022	$ 600,000	$ 628,500	$ 600,000	$ 649,500
5.5% senior notes due 2022	$ 600,000	$ 598,500	$ 600,000	$ 619,500
5.5% senior notes due 2023	$ 1,577,820	$ 1,573,875	$ 1,580,421	$ 1,627,834

Cash and cash equivalents, accounts receivable, other current assets, accounts payable, interest payable and other current liabilities. The carrying amounts approximate fair value due to the short maturity of these instruments.

Credit facility. The fair value of the Company's credit facility is estimated by discounting the principal and interest payments at the Company's credit-adjusted discount rate at the reporting date, which utilizes inputs that are Level 2 measurements in the fair value hierarchy.

Senior notes. The fair values of the Company's senior notes are based on quoted market prices. The debt securities are not actively traded and, therefore, are classified as Level 2 in the fair value hierarchy.

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Derivative instruments. The fair value of the Company's derivative instruments is estimated by management considering various factors, including closing exchange and over-the-counter quotations and the time value of the underlying commitments. Financial assets and liabilities are classified based on the lowest level of input that is significant to the fair value measurement. The Company's assessment of the significance of a particular input to the fair value measurement requires judgment and may affect the valuation of the fair value of assets and liabilities and their placement within the fair value hierarchy levels. The following tables summarize (i) the valuation of each of the Company's financial instruments by required fair value hierarchy levels and (ii) the gross fair value by the appropriate balance sheet classification, even when the derivative instruments are subject to netting arrangements and qualify for net presentation in the Company's consolidated balance sheets at December 31, 2014 and 2013. The Company nets the fair value of derivative instruments by counterparty in the Company's consolidated balance sheets.

	December 31, 2014					
	Fair Value Measurements Using					Net
(in thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:						
Commodity derivatives	$ -	$ 501,717	$ -	$ 501,717	$ (11,366)	$ 490,351
Noncurrent:						
Commodity derivatives	-	262,349	-	262,349	-	262,349
Liabilities						
Current:						
Commodity derivatives	-	(11,366)	-	(11,366)	11,366	-
Noncurrent:						
Commodity derivatives	-	-	-	-	-	-
Net derivative instruments	$ -	$ 752,700	$ -	$ 752,700	$ -	$ 752,700

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	December 31, 2013					
	Fair Value Measurements Using					Net
(in thousands)	Quoted Prices in Active Markets for Identical Assets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value	Gross Amounts Offset in the Consolidated Balance Sheet	Fair Value Presented in the Consolidated Balance Sheet
Assets						
Current:						
Commodity derivatives	$ -	$ 12,819	$ -	$ 12,819	$ (12,229)	$ 590
Noncurrent:						
Commodity derivatives	-	5,300	-	5,300	(4,334)	966
Liabilities						
Current:						
Commodity derivatives	-	(65,930)	-	(65,930)	12,229	(53,701)
Noncurrent:						
Commodity derivatives	-	(18,422)	-	(18,422)	4,334	(14,088)
Net derivative instruments	$ -	$ (66,233)	$ -	$ (66,233)	$ -	$ (66,233)

Concentrations of credit risk. As of December 31, 2014, the Company’s primary concentration of credit risks are the risk of collecting accounts receivable and the risk of counterparties’ failure to perform under derivative obligations. See Note 11 for information regarding the Company's major customers and derivative counterparties.

The Company has entered into International Swap Dealers Association Master Agreements (“ISDA Agreements”) with each of its derivative counterparties. The terms of the ISDA Agreements provide the Company and the counterparties with rights of set off upon the occurrence of defined acts of default by either the Company or a counterparty to a derivative, whereby the party not in default may set off all derivative liabilities owed to the defaulting party against all derivative asset receivables from the defaulting party. See Note 7 for additional information regarding the Company's derivative activities.

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Assets and Liabilities Measured at Fair Value on a Nonrecurring Basis

Certain assets and liabilities are reported at fair value on a nonrecurring basis in the Company’s consolidated balance sheets. The following methods and assumptions were used to estimate the fair values:

Impairments of long-lived assets – The Company reviews its long-lived assets to be held and used, including proved oil and natural gas properties, whenever events or circumstances indicate that the carrying value of those assets may not be recoverable, for instance when there are declines in commodity prices or well performance. An impairment loss is indicated if the sum of the expected undiscounted future net cash flows is less than the carrying amount of the assets. In this circumstance, the Company recognizes an impairment loss for the amount by which the carrying amount of the asset exceeds the estimated fair value of the asset. The Company reviews its oil and natural gas properties by depletion base or by individual well for those wells not constituting part of a depletion base. For each property determined to be impaired, an impairment loss equal to the difference between the carrying value of the properties and the estimated fair value of the properties would be recognized at that time.

The Company calculates the estimated fair values using a discounted future cash flow model. Management’s assumptions associated with the calculation of discounted future cash flows include commodity prices based on NYMEX futures price strips (Level 1), as well as Level 3 assumptions including (i) pricing adjustments for differentials, (ii) production costs, (iii) capital expenditures, (iv) production volumes and (v) estimated reserves.

As a result of management’s assessments, the Company recognized impairment charges to reduce the carrying values to their fair values. The following table reports the carrying amount, estimated fair value and impairment expense of long-lived assets for the indicated periods:

(in thousands)		Carrying Amount		Estimated Fair Value (Level 3)		Impairment Expense
December 2014	$	677,021	$	245,346	$	431,675
September 2014	$	26,790	$	11,314	$	15,476
June 2013	$	84,140	$	18,765	$	65,375

It is reasonably possible that the estimate of undiscounted future net cash flows may change in the future resulting in the need to further impair carrying values. The primary factors that may affect estimates of future cash flows are (i) commodity futures prices, (ii) increases or decreases in production and capital costs, (iii) future reserve adjustments, both positive and negative, to proved reserves and appropriate risk-adjusted probable and possible reserves and (iv) results of future drilling activities.

Additionally, based on the factors above as of December 31, 2014, the Company determined that undiscounted future cash flows attributable to certain depletion groups indicated that their carrying amounts were expected to be recovered; however, they may be at risk for impairment if management's estimates of future cash flows further decline.

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Note 7. ***Derivative financial instruments***

The Company uses derivative financial instruments to manage its exposure to commodity price fluctuations. Commodity derivative instruments are used to (i) reduce the effect of the volatility of price changes on the oil and natural gas the Company produces and sells, (ii) support the Company's capital budget and expenditure plans and (iii) support the economics associated with acquisitions. The Company does not enter into derivative financial instruments for speculative or trading purposes. The Company may also enter into physical delivery contracts to effectively provide commodity price hedges. Because these contracts are not expected to be net cash settled, they are considered to be normal sales contracts and not derivatives. Therefore, these contracts are not recorded in the Company's consolidated financial statements.

The Company does not designate its derivative instruments to qualify for hedge accounting. Accordingly, the Company reflects changes in the fair value of its derivative instruments in its statements of operations as they occur.

The following table summarizes the gains and losses reported in earnings related to the commodity derivative instruments for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Gain (loss) on derivatives not designated as hedges:			
Oil derivatives	$ 869,421	$ (133,890)	$ 127,293
Natural gas derivatives	21,496	10,238	150
Total	$ 890,917	$ (123,652)	$ 127,443

The following table represents the Company's cash receipts from (payments on) derivatives reported in the Company's cash flows from investing for the years ended December 31, 2014, 2013 and 2012:

Years Ended December 31,

(in thousands)	**2014**	**2013**	**2012**
Cash receipts from (payments on) derivatives not designated as hedges:			
Oil derivatives	$ 76,335	$ (41,616)	$ 22,411
Natural gas derivatives	(4,352)	9,275	1,125
Total	$ 71,983	$ (32,341)	$ 23,536

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Commodity derivative contracts at December 31, 2014. The following table sets forth the Company's outstanding derivative contracts at December 31, 2014. When aggregating multiple contracts, the weighted average contract price is disclosed. All of the Company's derivative contracts at December 31, 2014 are expected to settle by June 30, 2017.

		First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)						
2015:						
Volume (Bbl)		4,240,000	3,919,000	3,654,000	3,449,000	15,262,000
Price per Bbl	$	88.32$	87.50$	87.57$	87.42$	87.73
2016:						
Volume (Bbl)		3,218,000	3,068,000	2,958,000	105,000	9,349,000
Price per Bbl	$	90.43$	90.90$	90.46$	88.28$	90.57
2017:						
Volume (Bbl)		84,000	84,000	-	-	168,000
Price per Bbl	$	87.00$	87.00$	-$	-$	87.00
Oil Basis Swaps: (b)						
2015:						
Volume (Bbl)		3,915,000	3,836,500	3,634,000	3,404,000	14,789,500
Price per Bbl	$	(3.47)$	(3.45)$	(3.44)$	(3.38)$	(3.44)
Natural Gas Swaps: (c)						
2015:						
Volume (MMBtu)		5,850,000	5,915,000	5,980,000	5,980,000	23,725,000
Price per MMBtu	$	4.16$	4.16$	4.16$	4.16$	4.16
Natural Gas Basis Swaps: (d)						
2015:						
Volume (MMBtu)		1,350,000	1,365,000	1,380,000	1,380,000	5,475,000
Price per MMBtu	$	(0.13)$	(0.13)$	(0.13)$	(0.13)$	(0.13)

(a) The index prices for the oil price swaps are based on the NYMEX – West Texas Intermediate ("WTI") monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.
(c) The index prices for the natural gas price swaps are based on the NYMEX – Henry Hub last trading day futures price.
(d) The basis differential price is between the El Paso Permian delivery point and NYMEX – Henry Hub delivery point.

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Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, associated credit risk is mitigated by the Company's credit risk policies and procedures. See additional information in Note 11.

Note 8. *Debt*

The Company's debt consists of the following at December 31, 2014 and 2013:

	December 31,			
(in thousands)		**2014**		**2013**
Credit facility	$	139,500	$	250,000
7.0% unsecured senior notes due 2021		600,000		600,000
6.5% unsecured senior notes due 2022		600,000		600,000
5.5% unsecured senior notes due 2022		600,000		600,000
5.5% unsecured senior notes due 2023		1,550,000		1,550,000
Unamortized original issue premium (discount), net		27,820		30,421
Less: current portion		-		-
Total long-term debt	$	3,517,320	$	3,630,421

Credit facility. The Company's credit facility, as amended and restated (the "Credit Facility"), has a maturity date of May 9, 2019. The Company's borrowing base is $3.25 billion until the next scheduled borrowing base redetermination in May 2015, and commitments from the Company's bank group total $2.5 billion. Between scheduled borrowing base redeterminations, the Company and the lenders (requiring a 66 2/3 percent vote), may each request one special redetermination.

Advances on the Credit Facility bear interest, at the Company's option, based on (i) the prime rate of JPMorgan Chase Bank ("JPM Prime Rate") (3.25 percent at December 31, 2014) or (ii) a Eurodollar rate (substantially equal to the LIBOR). At December 31, 2014, the interest rates of Eurodollar rate advances and JPM Prime Rate advances varied, with interest margins ranging from 125 to 225 basis points and 25 to 125 basis points per annum, respectively, depending on the balance outstanding on the Credit Facility. During the years ended December 31, 2014, 2013 and 2012, the Company incurred commitment fees on the unused portion of the available commitments of $7.7 million, $8.3 million and $6.3 million, respectively. Under the current Credit Facility, commitment fees range from 30 to 37.5

basis points per annum. The Company had approximately $2.4 billion of unused commitments under its credit facility at December 31, 2014. Based on the Company's current ratio as defined in its credit facility as part of its financial covenants, at December 31, 2014, the Company's additional borrowings would be limited to approximately $1.6 billion.

The Company's obligations under the Credit Facility are secured by a first lien on substantially all of its oil and natural gas properties. At December 31, 2014, all of the Company's subsidiaries are guarantors and have had their equity pledged to secure borrowings under the Credit Facility.

The Credit Facility contains various restrictive covenants and compliance requirements which include:

- maintenance of certain financial ratios, including (i) maintenance of a quarterly ratio of total debt to consolidated earnings before interest expense, income taxes, depletion, depreciation, and amortization, exploration expense and other noncash income and expenses to be no greater than 4.25 to 1.0, and (ii) maintenance of a ratio of current assets to current liabilities, excluding noncash assets and liabilities related to financial derivatives and asset retirement obligations and including the unfunded amounts under the Credit Facility, to be not less than 1.0 to 1.0;

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- limits on the incurrence of certain indebtedness and certain types of liens;
- restrictions as to mergers, combinations and dispositions of assets; and
- limits on the payment of cash dividends.

The Company recorded a loss on extinguishment of debt related to the Credit Facility of approximately $4.3 million for the year ended December 31, 2014. This amount includes the proportional amount of unamortized deferred loan costs associated with banks with lesser commitments in the amended credit facility syndicate.

Senior notes. Interest on the Company's senior notes is paid in arrears semi-annually. The senior notes are fully and unconditionally guaranteed on a senior unsecured basis by all subsidiaries of the Company, subject to customary release provisions as described in Note 16.

On June 3, 2013, the Company received tenders and consents from the holders of approximately $225.6 million in aggregate principal amount, or approximately 75.2 percent, of its outstanding 8.625% senior notes due 2017 (the "8.625% Notes") in connection with a cash tender offer for any and all of the 8.625% Notes at a price of 106.922 percent of the unpaid principal amount.

On June 21, 2013, the Company redeemed the remaining outstanding 8.625% Notes not purchased in the tender offer at a redemption price of 106.516 percent of the unpaid principal amount plus accrued and unpaid interest through June 20, 2013.

The Company recorded a loss on extinguishment of debt related to the tender offer and redemption of its 8.625% Notes of approximately $28.6 million for the year ended December 31, 2013. This amount includes approximately $20.4 million associated with the premium paid for the tender offer and redemption of the notes, approximately $5.5 million of unamortized deferred loan costs and approximately $2.7 million of unamortized discount.

On June 4, 2013, the Company completed the issuance of an additional $850 million in principal amount of its 5.5% senior notes due 2023 (the "Offering") at 103.75 percent of par (resulting in a 4.884% yield) for net proceeds of approximately $867.8 million. The Company used a portion of the net proceeds from the Offering to fund the tender offer and redemption of the 8.625% Notes and to pay down amounts outstanding on the Credit Facility.

At December 31, 2014, the Company was in compliance with the covenants under its debt instruments.

Future benefit to interest expense from original issue premium at December 31, 2014 was as follows:

(in thousands)		
2015	$	2,747
2016		2,900
2017		3,062
2018		3,233
2019		3,413
Thereafter		12,465
Total	$	27,820

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Principal maturities of long-term debt. Principal maturities of long-term debt outstanding at December 31, 2014 are as follows:

(in thousands)		
2015	$	-
2016		-
2017		-
2018		-
2019		139,500
Thereafter		3,350,000
Total	$	3,489,500

Interest expense. The following amounts have been incurred and charged to interest expense for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,					
(in thousands)		**2014**		**2013**		**2012**
Cash payments for interest	$	211,342	$	200,961	$	158,715
Amortization of original issue discount (premium)		(2,599)		(1,248)		462
Amortization of deferred loan origination costs		10,937		13,172		11,958
Net changes in accruals		(737)		5,696		11,570
Interest costs incurred		218,943		218,581		182,705
Less: capitalized interest		(2,282)		-		-
Total interest expense	$	216,661	$	218,581	$	182,705

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Note 9. ***Commitments and contingencies***

Severance agreements. The Company has entered into severance and change in control agreements with all of its officers. The current annual salaries for the Company's officers covered under such agreements total approximately $7.4 million.

Indemnifications. The Company has agreed to indemnify its directors and officers with respect to claims and damages arising from certain acts or omissions taken in such capacity.

Legal actions. The Company is a party to proceedings and claims incidental to its business. While many of these matters involve inherent uncertainty, the Company believes that the amount of the liability, if any, ultimately incurred with respect to any such proceedings or claims will not have a material adverse effect on the Company's consolidated financial position as a whole or on its liquidity, capital resources or future results of operations. The Company will continue to evaluate proceedings and claims involving the Company on a regular basis and will establish and adjust any reserves as appropriate to reflect its assessment of the then current status of the matters.

Severance tax, royalty and joint interest audits. The Company is subject to routine severance, royalty and joint interest audits from regulatory bodies and non-operators and makes accruals as necessary for estimated exposure when deemed probable and estimable. Additionally, the Company is subject to various possible contingencies that arise primarily from interpretations affecting the oil and natural gas industry. Such contingencies include differing interpretations as to the prices at which oil and natural gas sales may be made, the prices at which royalty owners may be paid for production from their leases, allowable costs under joint interest arrangements and other matters. At December 31, 2014 and 2013, the Company had $12.3 million and $12.2 million accrued for estimated exposure, respectively. Although we believe that we have estimated our exposure with respect to the various laws and regulations, administrative rulings and interpretations thereof, adjustments could be required as new interpretations and regulations are issued.

Commitments. The Company periodically enters into contractual arrangements under which the Company is committed to expend funds. The following table summarizes the Company's commitments at December 31, 2014:

	Payments Due By Period						
(in thousands)	**Total**	**2015**	**2016**	**2017**	**2018**	**2019**	**Thereafter**

Purchase obligations (a)	$	167,174	$	57,489	$	30,017	$	15,080	$	21,077	$	7,606	$	35,905

(a) Relates to purchase agreements we have entered into including daywork drilling contracts, water commitment agreements, throughput volume delivery commitments and power commitments.

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Operating leases. The Company leases vehicles, equipment and office facilities under non-cancellable operating leases. Lease payments associated with these operating leases for the years ended December 31, 2014, 2013 and 2012 were approximately $7.2 million, $5.7 million and $4.7 million, respectively.

Future minimum lease commitments under non-cancellable operating leases at December 31, 2014 are as follows:

(in thousands)		
2015	$	7,245
2016		5,589
2017		5,577
2018		4,787
2019		4,112
Thereafter		8,905
Total	$	36,215

Note 10. ***Income taxes***

The Company uses an asset and liability approach for financial accounting and reporting for income taxes. The Company's objectives of accounting for income taxes are to recognize (i) the amount of taxes payable or refundable for the current year and (ii) deferred tax liabilities and assets for the future tax consequences of events that have been recognized in its financial statements or tax returns. The Company and its subsidiaries file a federal corporate income tax return on a consolidated basis. The tax returns and the amount of taxable income or loss are subject to examination by federal and state taxing authorities. At December 31, 2014 the Company had current income taxes receivable of approximately $32.9 million and current income taxes payable of approximately $1.1 million. At December 31, 2013 the Company had current income taxes receivable of approximately $10.7 million and current income taxes payable of approximately $1.7 million.

The Company continually assesses both positive and negative evidence to determine whether it is more likely than not that deferred tax assets can be realized prior to their expiration. Management monitors company-specific, oil and natural gas industry and worldwide economic factors and assesses the likelihood that the Company's net operating loss carryforwards ("NOLs"), if any, and other deferred tax attributes in the United States, state, and local tax jurisdictions will be utilized prior to their expiration. At December 31, 2014 and 2013, the Company had no valuation allowances related to its deferred tax assets.

At December 31, 2014, the Company did not have any significant uncertain tax positions requiring recognition in the financial statements. The tax years 2011 through 2014 remain subject to examination by the major tax jurisdictions.

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Notes to Consolidated Financial Statements

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Income tax provision. The Company’s income tax provision and amounts separately allocated were attributable to the following items for the years ended December 31, 2014, 2013 and 2012:

(in thousands)	Years Ended December 31, **2014**	**2013**	**2012**
Income from continuing operations	$ 317,785	$ 118,237	$ 251,041
Income from discontinued operations	-	7,518	14,519
Changes in stockholders' equity:			
Excess tax benefits related to stock-based compensation	(16,480)	(6,147)	(18,963)
	$ 301,305	$ 119,608	$ 246,597

The Company’s income tax provision attributable to income from continuing operations consisted of the following for the years ended December 31, 2014, 2013 and 2012:

(in thousands)	Years Ended December 31, **2014**	**2013**	**2012**
Current:			
U.S. federal	$ 16,621	$ 12,504	$ 7,066
U.S. state and local	4,997	3,306	2,156
Total current income tax provision	21,618	15,810	9,222
Deferred:			
U.S. federal	278,615	119,985	210,527
U.S. state and local	17,552	(17,558)	31,292
Total deferred income tax provision	296,167	102,427	241,819
Total income tax provision attributable to income from continuing operations	$ 317,785	$ 118,237	$ 251,041

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The reconciliation between the income tax expense computed by multiplying pretax income from continuing operations by the United States federal statutory rate and the reported amounts of income tax expense from continuing operations is as follows:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Income at U.S. federal statutory rate	$ 299,586	$ 125,006	$ 230,745
State income taxes (net of federal tax effect)	22,826	12,505	21,192
Revisions of previous estimates	738	1,400	219
Change in estimated effective statutory state income tax	(7,945)	(21,876)	-
Nondeductible expense & other	2,580	1,202	(1,115)
Income tax expense	$ 317,785	$ 118,237	$ 251,041
Effective tax rate	37.1%	33.1%	38.1%

The Company monitors changes in enacted tax rates for the jurisdictions in which it operates. During 2013, the state of New Mexico passed legislation to phase in a tax rate reduction over the next five years. In addition, the Company monitors its state tax apportionment footprint and makes updates for changes in its projected activity, including changes in budgets and drilling plans. Based upon the Company's projected future activity for the states in which it conducts business, the timing for when it anticipates its deferred tax items to become taxable and enacted tax rates at such time deferred items become taxable, the Company has revised its estimated state rate and recorded an additional deferred tax benefit of $7.9 million and $21.9 million during 2014 and 2013, respectively.

The Company's income tax provision attributable to income from discontinued operations consisted of the following for the years ended December 31, 2013 and 2012:

	Years Ended December 31,	
(in thousands)	**2013**	**2012**
Current:		
U.S. federal	$ 144	$ 14,023
U.S. state and local	25	1,667
Total current income tax expense	169	15,690
Deferred:		

U.S. federal	6,397	(1,392)
U.S. state and local	952	221
Total deferred income tax provision	7,349	(1,171)
Total income tax provision attributable to income from discontinued operations	$ 7,518	$ 14,519

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The tax effects of temporary differences that give rise to significant portions of the deferred tax assets and deferred tax liabilities were as follows:

(in thousands)	December 31, 2014	2013
Deferred tax assets:		
Stock-based compensation	$ 24,810	$ 23,262
Derivative instruments	-	24,904
Asset retirement obligation	44,802	38,241
Other	24,368	9,500
Total deferred tax assets	93,980	95,907
Deferred tax liabilities:		
Oil and natural gas properties, principally due to differences in basis and depreciation and the deduction of intangible drilling costs for tax purposes	(1,396,756)	(1,383,929)
Intangible assets - operating rights	(10,148)	(10,759)
Derivative instruments	(281,303)	-
Other	(6,524)	(5,803)
Total deferred tax liability	(1,694,731)	(1,400,491)
Net deferred tax liability	$ (1,600,751)	$ (1,304,584)

Note 11. ***Major customers and derivative counterparties***

Sales to major customers. The Company’s share of oil and natural gas production is sold to various purchasers. The Company is of the opinion that the loss of any one purchaser would not have a material adverse effect on the ability of the Company to sell its oil and natural gas production.

The following purchasers individually accounted for 10 percent or more of the consolidated oil and natural gas revenues, including the revenues from discontinued operations, during the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31, 2014	2013	2012

Holly Frontier Refining and Marketing, LLC	17%	30%	26%
Enterprise Crude Oil LLC	12%	13%	6%
Western Refining Company LP	12%	1%	-
Phillips 66	8%	6%	14%

At December 31, 2014, the Company had receivables from Holly Frontier Refining and Marketing, LLC, Enterprise Crude Oil LLC and Western Refining Company LP of $48.6 million, $23.0 million and $19.3 million, respectively, which are reflected in accounts receivable — oil and natural gas in the accompanying consolidated balance sheets.

Derivative counterparties. The Company uses credit and other financial criteria to evaluate the credit standing of, and to select, counterparties to its derivative instruments. The Company's Credit Facility requires that the senior unsecured debt ratings of the Company's derivative counterparties be (i) not less than either A- by Standard & Poor's Rating Group rating system or A3 by Moody's Investors Service, Inc. rating system or (ii) a lender or related affiliate under the Company's Credit Facility. At December 31, 2014 and 2013, the counterparties with whom the Company had outstanding derivative contracts met or exceeded these criteria. Although the Company does not obtain collateral or otherwise secure the fair value of its derivative instruments, management believes the associated credit risk is mitigated by the Company's credit risk policies and procedures and by the criteria of the Company's Credit Facility.

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At December 31, 2014, the Company had a net asset position of $752.7 million as a result of outstanding derivative contracts from the following counterparties:

(in thousands)		
J.P. Morgan Chase Bank	$	134,735
Wells Fargo Bank, N.A.		84,523
Barclays Bank PLC		81,979
Bank of Montreal		59,789
KeyBank National Association		59,702
Citibank, N.A.		55,826
Canadian Imperial Bank of Commerce		48,466
Merrill Lynch Commodities, Inc.		46,738
Union Bank, N.A.		33,986
Natixis		32,874
ING Capital Markets LLC		30,496
Other		83,586
Total	$	752,700

Note 12. ***Related party transactions***

The following table summarizes payments made to related parties and reported in the Company's consolidated statements of operations for the periods presented:

	Years Ended December 31,					
(in thousands)		**2014**		**2013**		**2012**
Amounts paid to a partnership in which a director has an ownership interest (a)	$	15,181	$	7,255	$	2,444
Royalties paid to a director and certain officers of the Company (b)	$	383	$	43	$	77
Amounts paid under consulting agreement with Steven L. Beal (c)	$	-	$	865	$	251

(a) Amounts include royalties on certain properties and lease bonus payments paid to a partnership in which a director of the Company is the general partner and owns a 3.5 percent partnership interest.

(b) Payments made to a director and certain officers (or affiliated entities) who own revenue, overriding royalty interests or net profits interests in properties owned by the Company.

(c) On June 30, 2009, Steven L. Beal, the Company's then-president and chief operating officer, retired from such positions. On June 9, 2009, the Company entered into a consulting agreement (the "Consulting Agreement") with Mr. Beal, under which Mr. Beal began serving as a consultant to the Company on July 1, 2009. During the term of the consulting relationship, Mr. Beal received a consulting fee of $20,000 per month and a monthly reimbursement for his medical and dental coverage costs. In August 2013, the Company and Mr. Beal mutually terminated the Consulting Agreement in exchange for the payment to Mr. Beal of $720,000, which termination and payment were approved by the disinterested members of the Company's Board of Directors.

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At December 31, 2014, the Company had a $76,000 receivable from an officer (or affiliated entities) related to certain properties it operates.

In June 2013, in connection with the tender offer for the 8.625% Notes, certain directors and officers received an aggregate amount of approximately $1.3 million for the 8.625% Notes they owned. The tender offer was approved by the disinterested members of the Company's Board of Directors.

Note 13. ***Discontinued operations***

In December 2012, the Company closed the sale of certain of its non-core assets for cash consideration of approximately $503.1 million, which resulted in a pre-tax gain of approximately $0.9 million. As a result of post-closing adjustments during the year ended December 31, 2013, the Company made a positive adjustment to gain (loss) on disposition of assets of approximately $19.6 million. The Company reflected the results of operations of this divestiture as discontinued operations, rather than as a component of continuing operations.

The following table represents the components of the Company's discontinued operations for the years ended December 31, 2013 and 2012:

(in thousands)	Years Ended December 31, 2013	2012
Operating revenues:		
Oil sales	$ -	$ 101,359
Natural gas sales	-	18,578
Total operating revenues	-	119,937
Operating costs and expenses:		
Oil and natural gas production	-	34,270
Exploration and abandonments	-	334
Depreciation, depletion and amortization (a)	-	30,140
Accretion of discount on asset retirement obligations (a)	-	1,004
General and administrative (b)	-	(2,493)
Total operating costs and expenses	-	63,255
Income from operations	-	56,682
Other income (expense):		

Gain (loss) on disposition of assets, net (a)		19,599		(18,704)
Income from discontinued operations before income taxes		19,599		37,978
Income tax benefit (expense):				
Current		(169)		(15,690)
Deferred (a)		(7,349)		1,171
Income from discontinued operations, net of tax	$	12,081	$	23,459

(a) Represents the significant non-cash components of discontinued operations.

(b) Represents the fees received from third-parties for operating oil and natural gas properties that were sold. The Company reflects these fees as a reduction of general and administrative expenses.

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Note 14. ***Net income per share***

The Company uses the two-class method of calculating net income per share because certain of the Company's unvested share-based awards qualify as participating securities. Participating securities participate in income proportionate to the weighted average number of outstanding common shares, but are not assumed to participate in the Company's net losses because they are not contractually obligated to do so. Accordingly, allocations of earnings to participating securities are included in the Company's calculations of basic and diluted earnings per share from continuing operations, discontinued operations and net income attributable to common stockholders.

The following tables reconcile the Company's income from continuing operations, income from discontinued operations and net income attributable to common stockholders to the basic and diluted earnings used to determine the Company's income per share amounts for the years ended December 31, 2014, 2013 and 2012, respectively, under the two-class method:

	Year Ended December 31, 2014		
(in thousands, except per share amounts)	**Continuing Operations**	**Discontinued Operations**	**Total**
Income as reported	$ 538,175	$ -	$ 538,175
Participating basic earnings	(5,961)	-	(5,961)
Basic income attributable to common stockholders	532,214	-	532,214
Reallocation of participating earnings	16	-	16
Diluted income attributable to common stockholders	$ 532,230	$ -	$ 532,230
Income per common share:			
Basic	$ 4.89	$ -	$ 4.89
Diluted	$ 4.88	$ -	$ 4.88

Year Ended
December 31, 2013

(in thousands, except per share amounts)	Continuing Operations	Discontinued Operations	Total
Income as reported	$ 238,922	$ 12,081	$ 251,003
Participating basic earnings	(2,610)	(132)	(2,742)
Basic income attributable to common stockholders	236,312	11,949	248,261
Reallocation of participating earnings	4	-	4
Diluted income attributable to common stockholders	$ 236,316	$ 11,949	$ 248,265
Income per common share:			
Basic	$ 2.28	$ 0.11	$ 2.39
Diluted	$ 2.28	$ 0.11	$ 2.39

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	Year Ended December 31, 2012		
(in thousands, except per share amounts)	**Continuing Operations**	**Discontinued Operations**	**Total**
Income as reported	$ 408,230	$ 23,459	$ 431,689
Participating basic earnings	-	-	-
Basic income attributable to common stockholders	408,230	23,459	431,689
Reallocation of participating earnings	-	-	-
Diluted income attributable to common stockholders	$ 408,230	$ 23,459	$ 431,689
Income per common share:			
Basic	$ 3.96	$ 0.22	$ 4.18
Diluted	$ 3.93	$ 0.22	$ 4.15

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The following table is a reconciliation of the basic weighted average common shares outstanding to diluted weighted average common shares outstanding for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Weighted average common shares outstanding:			
Basic	108,844	103,744	103,190
Dilutive common stock options	83	165	354
Dilutive restricted stock	-	-	428
Dilutive performance units	205	4	-
Diluted	109,132	103,913	103,972

The following table is a summary of the restricted stock and performance units, which were not included in the computation of diluted net income per share, as inclusion of these items would be antidilutive:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Number of antidilutive common shares:			
Antidilutive restricted stock	153	9	95
Antidilutive performance units	-	83	-

Note 15. ***Other current liabilities***

The following table provides the components of the Company's other current liabilities at December 31, 2014 and 2013:

(in thousands)	December 31, 2014	2013
Other current liabilities:		
Accrued production costs	$ 70,786	$ 48,196
Payroll related matters	34,349	28,498
Accrued interest	69,264	70,000
Asset retirement obligations	9,146	4,481
Other	11,763	5,425
Other current liabilities	$ 195,308	$ 156,600

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Note 16. ***Subsidiary guarantors***

All of the Company's 100 percent owned and controlled subsidiaries have fully and unconditionally guaranteed the Company's senior notes. The indentures governing the Company's senior notes provide that the guarantees of its subsidiary guarantors will be released in certain customary circumstances including (i) in connection with any sale, exchange or other disposition, whether by merger, consolidation or otherwise, of the capital stock of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, such that, after giving effect to such transaction, such guarantor would no longer constitute a subsidiary of the Company, (ii) in connection with any sale, exchange or other disposition (other than a lease) of all or substantially all of the assets of that guarantor to a person that is not the Company or a restricted subsidiary of the Company, (iii) upon the merger of a guarantor into the Company or any other guarantor or the liquidation or dissolution of a guarantor, (iv) if the Company designates any restricted subsidiary that is a guarantor to be an unrestricted subsidiary in accordance with the indenture, (v) upon legal defeasance or satisfaction and discharge of the indenture and (vi) upon written notice of such release or discharge by the Company to the trustee following the release or discharge of all guarantees by such guarantor of any indebtedness that resulted in the creation of such guarantee, except a discharge or release by or as a result of payment under such guarantee.

See Note 8 for a summary of the Company's senior notes. In accordance with practices accepted by the United States Securities and Exchange Commission ("SEC"), the Company has prepared condensed consolidating financial statements in order to quantify the assets, results of operations and cash flows of such subsidiaries as subsidiary guarantors. One of the entities included in the Company's consolidated financial statements was formed to effectuate a tax-free exchange of assets. The third-party conveyed ownership to the Company upon completion of the tax-free exchange process. This entity did not guarantee the Company's senior notes until the conveyance was completed and is referred to as a "Non-Guarantor Subsidiary" in the tables below.

The following condensed consolidating balance sheets at December 31, 2014 and 2013, condensed consolidating statements of operations and consolidating condensed statements of cash flows for the years ended December 31, 2014, 2013 and 2012, present financial information for Concho Resources Inc. as the Parent on a stand-alone basis (carrying any investments in subsidiaries under the equity method), financial information for the subsidiary guarantors on a stand-alone basis (carrying any investment in non-guarantor subsidiaries under the equity method), financial information for the subsidiary non-guarantor on a stand-alone basis and the consolidation and elimination entries necessary to arrive at the information for the Company on a consolidated basis. All current and deferred income taxes are recorded on Concho Resources Inc., as the subsidiaries are flow-through entities for income tax purposes. The subsidiary guarantors and subsidiary non-guarantor are not restricted from making distributions to the Company.

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Notes to Consolidated Financial Statements

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Condensed Consolidating Balance Sheet
December 31, 2014

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 6,670,744	$ 1,201,950	$ (7,872,694)	$ -
Other current assets	569,545	618,851	-	1,188,396
Oil and natural gas properties, net	-	10,076,878	-	10,076,878
Property and equipment, net	-	129,136	-	129,136
Investment in subsidiaries	4,085,045	-	(4,085,045)	-
Other long-term assets	330,792	74,761	-	405,553
Total assets	$ 11,656,126	$ 12,101,576	$ (11,957,739)	$ 11,799,963
LIABILITIES AND EQUITY				
Accounts payable - related parties	$ 1,201,950	$ 6,670,744	$ (7,872,694)	$ -
Other current liabilities	217,884	1,209,309	-	1,427,193
Long-term debt	3,517,320	-	-	3,517,320
Other long-term liabilities	1,438,184	136,478	-	1,574,662
Equity	5,280,788	4,085,045	(4,085,045)	5,280,788
Total liabilities and equity	$ 11,656,126	$ 12,101,576	$ (11,957,739)	$ 11,799,963

Condensed Consolidating Balance Sheet
December 31, 2013

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
ASSETS				
Accounts receivable - related parties	$ 6,115,554	$ 1,261,844	$ (7,377,398)	$ -
Other current assets	39,108	481,767	-	520,875
Oil and natural gas properties, net	-	8,831,265	-	8,831,265
Property and equipment, net	-	114,783	-	114,783
Investment in subsidiaries	3,896,741	-	(3,896,741)	-
Other long-term assets	74,013	50,228	-	124,241
Total assets	$ 10,125,416	$ 10,739,887	$ (11,274,139)	$ 9,591,164
LIABILITIES AND EQUITY				
Accounts payable - related parties	$ 1,261,844	$ 6,115,554	$ (7,377,398)	$ -

Other current liabilities		126,461		630,407		-		756,868
Long-term debt		3,630,421		-		-		3,630,421
Other long-term liabilities		1,348,741		97,185		-		1,445,926
Equity		3,757,949		3,896,741		(3,896,741)		3,757,949
Total liabilities and equity	$	10,125,416	$	10,739,887	$	(11,274,139)	$	9,591,164

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Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2014

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 2,660,147	$ -	$ 2,660,147
Total operating costs and expenses	888,632	(2,459,034)	-	(1,570,402)
Income from operations	888,632	201,113	-	1,089,745
Interest expense	(216,661)	-	-	(216,661)
Loss on extinguishment of debt	(4,316)	-	-	(4,316)
Other, net	188,305	(12,809)	(188,304)	(12,808)
Income before income taxes	855,960	188,304	(188,304)	855,960
Income tax expense	(317,785)	-	-	(317,785)
Net income	$ 538,175	$ 188,304	$ (188,304)	$ 538,175

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2013

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Total operating revenues	$ -	$ 2,319,919	$ -	$ 2,319,919
Total operating costs and expenses	(125,924)	(1,576,558)	-	(1,702,482)
Income (loss) from operations	(125,924)	743,361	-	617,437
Interest expense	(218,581)	-	-	(218,581)
Loss on extinguishment of debt	(28,616)	-	-	(28,616)
Other, net	749,878	(13,136)	(749,823)	(13,081)
Income before income taxes	376,757	730,225	(749,823)	357,159
Income tax expense	(118,237)	-	-	(118,237)
Income from continuing operations	258,520	730,225	(749,823)	238,922
Income (loss) from discontinued operations, net of tax	(7,517)	19,598	-	12,081
Net income	$ 251,003	$ 749,823	$ (749,823)	$ 251,003

Condensed Consolidating Statement of Operations
For the Year Ended December 31, 2012

(in thousands)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total

Total operating revenues	$	-	$	1,812,472	$	7,342	$	-	$	1,819,814
Total operating costs and expenses		126,482		(1,090,013)		(5,720)		-		(969,251)
Income from operations		126,482		722,459		1,622		-		850,563
Interest expense		(182,705)		-		-		-		(182,705)
Other, net		753,472		(3,148)		(6,043)		(752,868)		(8,587)
Income (loss) before income taxes		697,249		719,311		(4,421)		(752,868)		659,271
Income tax expense		(251,041)		-		-		-		(251,041)
Income (loss) from continuing operations		446,208		719,311		(4,421)		(752,868)		408,230
Income (loss) from discontinued operations, net of tax		(14,519)		37,978		-		-		23,459
Net income (loss)	$	431,689	$	757,289	$	(4,421)	$	(752,868)	$	431,689

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Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2014, 2013 and 2012

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2014

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (888,369)	$ 2,562,156	$ -	$ 1,673,787
Net cash flows provided by (used in) investing activities	71,983	(2,617,979)	-	(2,545,996)
Net cash flows provided by financing activities	816,386	55,823	-	872,209
Net decrease in cash and cash equivalents	-	-	-	-
Cash and cash equivalents at beginning of period	-	21	-	21
Cash and cash equivalents at end of period	$ -	$ 21	$ -	$ 21

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2013

(in thousands)	Parent Issuer	Subsidiary Guarantors	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (487,131)	$ 1,849,151	$ -	$ 1,362,020
Net cash flows used in investing activities	(32,341)	(1,864,453)	-	(1,896,794)
Net cash flows provided by financing activities	519,472	12,443	-	531,915
Net decrease in cash and cash equivalents	-	(2,859)	-	(2,859)
Cash and cash equivalents at beginning of period	-	2,880	-	2,880
Cash and cash equivalents at end of period	$ -	$ 21	$ -	$ 21

Condensed Consolidating Statement of Cash Flows
For the Year Ended December 31, 2012

(in thousands)	Parent Issuer	Subsidiary Guarantors	Subsidiary Non-Guarantor	Consolidating Entries	Total
Net cash flows provided by (used in) operating activities	$ (1,044,006)	$ 2,278,647	$ 2,837	$ -	$ 1,237,478
Net cash flows provided by (used in) investing activities	23,536	(1,720,242)	(543,738)	-	(2,240,444)

Net cash flows provided by (used in) financing activities	1,020,470	(555,867)	540,901	-	1,005,504
Net increase in cash and cash equivalents	-	2,538	-	-	2,538
Cash and cash equivalents at beginning of period	-	342	-	-	342
Cash and cash equivalents at end of period	$ -	$ 2,880	$ -	$ -	$ 2,880

Concho Resources Inc.

Notes to Consolidated Financial Statements

December 31, 2014, 2013 and 2012

Note 17. ***Subsequent events***

New commodity derivative contracts. After December 31, 2014, the Company entered into the following additional oil price swaps and oil basis swaps to hedge additional amounts of the Company's estimated future production:

	First Quarter	Second Quarter	Third Quarter	Fourth Quarter	Total
Oil Swaps: (a)					
2015:					
Volume (Bbl)	-	660,000	660,000	660,000	1,980,000
Price per Bbl	$ -	$ 56.60	$ 56.60	$ 56.60	$ 56.60
2016:					
Volume (Bbl)	180,000	180,000	180,000	2,610,000	3,150,000
Price per Bbl	$ 61.04	$ 61.04	$ 61.04	$ 62.48	$ 62.23
Oil Basis Swaps: (b)					
2016:					
Volume (Bbl)	364,000	364,000	368,000	368,000	1,464,000
Price per Bbl	$ (2.48)	$ (2.48)	$ (2.48)	$ (2.48)	$ (2.48)

(a) The index prices for the oil price swaps are based on the NYMEX – WTI monthly average futures price.
(b) The basis differential price is between Midland – WTI and Cushing – WTI.

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2014, 2013 and 2012

Capitalized costs

(in thousands)	December 31, 2014	2013
Oil and natural gas properties:		
Proved	$ 12,795,970	$ 10,182,953
Unproved	1,071,861	1,032,420
Less: accumulated depletion	(3,790,953)	(2,384,108)
Net capitalized costs for oil and natural gas properties	$ 10,076,878	$ 8,831,265

Costs incurred for oil and natural gas producing activities (a)

(in thousands)	Years Ended December 31, 2014	2013	2012
Property acquisition costs:			
Proved	$ 99,362	$ 11,499	$ 857,836
Unproved	292,363	85,538	441,042
Exploration	1,615,238	1,029,793	781,174
Development	937,491	738,430	741,206
Total costs incurred for oil and natural gas properties	$ 2,944,454	$ 1,865,260	$ 2,821,258

(a) The costs incurred for oil and natural gas producing activities includes the following amounts of asset retirement obligations:

(in thousands)	Years Ended December 31, 2014	2013	2012
Exploration costs	$ 2,589	$ 2,672	$ 2,611
Development costs	7,488	9,467	15,536
Total asset retirement obligations	$ 10,077	$ 12,139	$ 18,147

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2014, 2013 and 2012

Reserve Quantity Information

The following information represents estimates of the Company's proved reserves as of December 31, 2014. The pricing that was used for estimates of the Company's reserves as of December 31, 2014 was based on the SEC pricing of $91.48 per Bbl West Texas Intermediate posted oil price and $4.35 per MMBtu Henry Hub spot natural gas price. See table below.

Subject to limited exceptions, proved undeveloped reserves may only be booked if they relate to wells scheduled to be drilled within five years of the date of booking. This rule limited, and may continue to limit, the Company's potential to record additional proved undeveloped reserves as it pursues its drilling program, particularly as it develops its significant acreage in the Permian Basin of Southeast New Mexico and West Texas. Moreover, the Company may be required to write down its proved undeveloped reserves if it does not drill on those reserves with the required five-year timeframe. The Company does not have any proved undeveloped reserves which have remained undeveloped for five years or more.

The Company's proved oil and natural gas reserves are all located in the United States, primarily in the Permian Basin of Southeast New Mexico and West Texas. All of the estimates of the proved reserves at December 31, 2014, 2013 and 2012 are based on reports prepared by Cawley, Gillespie & Associates, Inc. and Netherland, Sewell & Associates, Inc., independent petroleum engineers. Proved reserves were estimated in accordance with the guidelines established by the SEC and the FASB.

The following table summarizes the prices utilized in the reserve estimates for 2014, 2013 and 2012. Commodity prices utilized for the reserve estimates prior to adjustments for location, grade and quality are as follows:

	December 31, 2014	2013	2012
Prices utilized in the reserve estimates before adjustments:			
Oil per Bbl	$ 91.48	$ 93.42	$ 91.21
Natural gas per MMBtu	$ 4.35	$ 3.67	$ 2.76

Oil and natural gas reserve quantity estimates are subject to numerous uncertainties inherent in the estimation of quantities of proved reserves and in the projection of future rates of production and the timing of development expenditures. The accuracy of such estimates is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of subsequent drilling, testing and production may cause either upward or downward revision of previous estimates. Further, the volumes considered to be commercially recoverable fluctuate with changes in prices and operating costs. The Company emphasizes that reserve estimates are inherently imprecise and that estimates of new discoveries are more imprecise than those of currently producing oil and natural gas properties. Accordingly, these estimates are expected to change as additional information becomes available in the future.

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2014, 2013 and 2012

The following table provides a rollforward of the total proved reserves for the years ended December 31, 2014, 2013 and 2012, as well as proved developed and proved undeveloped reserves at the beginning and end of each respective year. Oil and condensate volumes are expressed in MBbls and natural gas volumes are expressed in MMcf.

	2014			2013			2012	
	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Oil and Condensate (MBbls)	Natural Gas (MMcf)	Total (MBoe)	Oil and Condensate (MBbls)	Natural Gas (MMcf)
Total Proved Reserves:								
Balance, January 1	307,382	1,173,240	502,921	273,508	1,042,079	447,188	238,296	889,34
Purchases of minerals-in-place	2,543	18,970	5,705	889	4,016	1,558	30,269	157,26
Sales of minerals-in-place	-	-	-	-	-	-	(21,467)	(82,824
Extensions and discoveries	115,389	400,329	182,111	72,025	199,886	105,339	60,358	189,37
Revisions of previous estimates	(28,648)	95,812	(12,679)	(17,914)	2,313	(17,529)	(15,945)	(40,490
Production	(26,319)	(87,336)	(40,875)	(21,126)	(75,054)	(33,635)	(18,003)	(70,591
Balance, December 31	370,347	1,601,015	637,183	307,382	1,173,240	502,921	273,508	1,042,07
Proved Developed Reserves:								
January 1	179,520	742,417	303,255	160,936	665,419	271,839	143,912	552,10
December 31	211,446	992,567	376,874	179,520	742,417	303,255	160,936	665,41
Proved Undeveloped Reserves:								
January 1	127,862	430,823	199,666	112,572	376,660	175,349	94,384	337,24
December 31	158,901	608,448	260,309	127,862	430,823	199,666	112,572	376,66

Purchases of minerals-in-place. The Company's purchases of minerals-in-place are composed of approximately 5.7 MMBoe from various acquisitions throughout the year.

Extensions and discoveries. Extensions and discoveries of approximately 182.1 MMBoe are primarily the result of the Company's continued success from its extension and infill horizontal drilling programs in its core operating areas. There were approximately 61.3 MMBoe of proved developed reserves that were directly added through the Company's drilling activity last year. Based upon this activity, approximately 120.8 MMBoe of new proved undeveloped locations were added, of which, approximately 73.2 MMBoe of proved undeveloped reserves were one offset location from an existing producing well. In addition, within some of the Company's core operating areas, one or more reliable technologies supported additional proved undeveloped locations that are more than one offset away from a producing well. There were approximately 300 such proved undeveloped locations added based on reliable technology. These locations resulted in 47.6 MMBoe of net proved reserves.

Revisions of previous estimates. Revisions of previous estimates are comprised of (i) 36.2 MMBoe of proved undeveloped reserves reclassified to unproved reserves because they are no longer expected to be developed within the five years of their initial recording required by SEC rules, (ii) a 23.6 MMBoe net positive revision resulting from both positive and negative technical and performance evaluations and (iii) 0.1 MMBoe of negative price revisions.

Standardized Measure of Discounted Future Net Cash Flows

The standardized measure of discounted future net cash flows is computed by applying the 12-month unweighted average of the first-day-of-the-month pricing for oil and natural gas (with consideration of price changes only to the extent provided by contractual arrangements) to the estimated future production of proved oil and natural gas reserves less estimated future expenditures (based on year-end costs) to be incurred in developing and producing the proved reserves, discounted using a rate of 10 percent per year to reflect the estimated timing of the future cash flows. Future income taxes are calculated by comparing undiscounted future cash flows to the tax basis of oil and natural gas properties plus available carryforwards and credits and applying the current tax rates to the difference.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of oil and natural gas properties. Estimates of fair value would also consider probable and possible reserves, anticipated future oil and natural gas prices, interest rates, changes in development and production costs and risks associated with future production. Because of these and other considerations, any estimate of fair value is necessarily subjective and imprecise.

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2014, 2013 and 2012

The following table provides the standardized measure of discounted future net cash flows at December 31, 2014, 2013 and 2012:

	December 31,		
(in thousands)	**2014**	**2013**	**2012**
Oil and gas producing activities:			
Future cash inflows	$ 42,162,518	$ 34,428,001	$ 30,788,562
Future production costs	(11,878,549)	(10,180,985)	(8,918,568)
Future development and abandonment costs (a)	(4,665,495)	(3,808,507)	(3,212,756)
Future income tax expense	(7,565,280)	(6,304,087)	(5,688,745)
Future net cash flows	18,053,194	14,134,422	12,968,493
10% annual discount factor	(10,030,367)	(7,889,987)	(7,180,420)
Standardized measure of discounted future net cash flows	$ 8,022,827	$ 6,244,435	$ 5,788,073

(a) Includes $203.9 million, $173.5 million and $154.0 million of undiscounted asset retirement cash outflow estimated at December 31, 2014, 2013 and 2012, respectively, using current estimates of future abandonment costs less salvage values. See Note 4 for corresponding information regarding the Company's discounted asset retirement obligations.

Changes in Standardized Measure of Discounted Future Net Cash Flows

The following table provides a rollforward of the standardized measure of discounted future net cash flows for the years ended December 31, 2014, 2013 and 2012:

	Years Ended December 31,		
(in thousands)	**2014**	**2013**	**2012**
Oil and natural gas producing activities:			
Purchases of minerals-in-place	$ 102,032	$ 19,331	$ 875,992
Sales of minerals-in-place	-	-	(614,183)
Extensions and discoveries	3,353,339	2,036,404	1,881,067
Development costs incurred during the period	561,198	441,998	411,576
Net changes in prices and production costs	(645,947)	(344,763)	(1,089,627)
Oil and natural gas sales, net of production costs	(2,121,773)	(1,864,483)	(1,561,738)
Changes in future development costs	310,326	155,489	100,669

Revisions of previous quantity estimates	(250,401)	(363,615)	(494,886)
Accretion of discount	906,661	833,226	888,804
Changes in production rates, timing and other	139,885	(211,099)	(470,513)
Change in present value of future net revenues	2,355,320	702,488	(72,839)
Net change in present value of future income taxes	(576,928)	(246,126)	159,772
	1,778,392	456,362	86,933
Balance, beginning of year	6,244,435	5,788,073	5,701,140
Balance, end of year	$ 8,022,827	$ 6,244,435	$ 5,788,073

Concho Resources Inc.

Unaudited Supplementary Data

December 31, 2014, 2013 and 2012

Selected Quarterly Financial Results

The following table provides selected quarterly financial results for the years ended December 31, 2014 and 2013:

	Quarter			
(in thousands, except per share data)	**First**	**Second**	**Third**	**Fourth**
Year ended December 31, 2014:				
Total operating revenues	$ 660,959	$ 704,702	$ 700,263	$ 594,223
Operating costs and expenses (excluding gains (losses) on derivatives not designated as hedges)	(423,112)	(451,934)	(484,480)	(1,101,793)
Gains (losses) on derivatives not designated as hedges	(35,615)	(164,707)	326,229	765,010
Income from operations	$ 202,232	$ 88,061	$ 542,012	$ 257,440
Net income	$ 91,307	$ 11,769	$ 305,203	$ 129,896
Net income per common share - Basic	$ 0.87	$ 0.11	$ 2.70	$ 1.15
Net income per common share - Diluted	$ 0.87	$ 0.11	$ 2.69	$ 1.15
Year ended December 31, 2013:				
Total operating revenues	$ 472,127	$ 562,786	$ 652,920	$ 632,086
Operating costs and expenses (excluding gains (losses) on derivatives not designated as hedges)	(332,359)	(412,155)	(374,258)	(460,058)
Gains (losses) on derivatives not designated as hedges	(59,017)	70,324	(168,610)	33,651
Income from operations	$ 80,751	$ 220,955	$ 110,052	$ 205,679
Income (loss) from discontinued operations, net of tax	$ 12,534	$ (453)	$ -	$ -
Net income	$ 30,093	$ 84,700	$ 30,421	$ 105,789
Net income per common share - Basic	$ 0.29	$ 0.81	$ 0.29	$ 1.01
Net income per common share - Diluted	$ 0.29	$ 0.81	$ 0.29	$ 1.01

Exhibit Number		
1.1		Underwriting Agreement dated May 12, 2014, by and between Concho Resources Inc. and Goldman, Sachs & Co.
3.1		Restated Certificate of Incorporation (filed as Exhibit 3.1 to the Company's Current Report on Form 8-K on Augus
3.2		Second Amended and Restated Bylaws of Concho Resources Inc., as amended November 7, 2012 (filed as Exhibit
4.1		Specimen Common Stock Certificate (filed as Exhibit 4.1 to the Company’s Annual Report on Form 10-K on Febr
4.2		Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guarantors named therein, an
4.3		First Supplemental Indenture, dated September 18, 2009, between Concho Resources Inc., the subsidiary guaranto
4.4		Second Supplemental Indenture, dated November 3, 2010, between Concho Resources Inc., the subsidiary guarant
4.5		Third Supplemental Indenture, dated December 14, 2010, between Concho Resources Inc., the subsidiary guaranto
4.6		Fourth Supplemental Indenture, dated May 23, 2011, between Concho Resources Inc., the subsidiary guarantors na
4.7		Fifth Supplemental Indenture, dated December 12, 2011, between Concho Resources Inc., the subsidiary guaranto
4.8		Sixth Supplemental Indenture, dated March 12, 2012, between Concho Resources Inc., the subsidiary guarantors n
4.9		Seventh Supplemental Indenture, dated August 17, 2012, between Concho Resources Inc., the subsidiary guaranto
4.10		Eighth Supplemental Indenture, dated June 3, 2013, between Concho Resources Inc., the subsidiary guarantors nar
4.11		Form of 7.0% Senior Notes due 2021 (included in Exhibit 4.1 to the Company’s Current Report on Form 8-K on D
4.12		Form of 6.5% Senior Notes due 2022 (included in Exhibit 4.1 to the Company’s Current Report on Form 8-K on M
4.13		Form of 5.5% Senior Notes due 2022 (included in Exhibit 4.2 to the Company’s Current Report on Form 8-K on M
4.14		Form of 5.5% Senior Notes due 2023 (included in Exhibit 4.1 to the Company’s Current Report on Form 8-K on A
10.1	**	Separation and Release Agreement dated January 2, 2013, between Concho Resources Inc. and Jack F. Harper (fil
10.2	**	Form of Performance Unit Award Agreement (filed as Exhibit 10.1 to the Company’s Current Report on Form 8-K
10.3	**	Termination of Consulting Agreement dated August 14, 2013 by and between Concho Resources Inc. and Steven
10.4	**	Amended and Restated Concho Resources Inc. 2006 Stock Incentive Plan (filed as Exhibit 10.1 to the Company’s
10.5	**	Form of Nonstatutory Stock Option Agreement (filed as Exhibit 10.16 to the Company’s Annual Report on Form
10.6	**	Form of Restricted Stock Agreement (for officers) (filed as Exhibit 10.11 to the Company’s Annual Report on For
10.7	**	Form of Restricted Stock Agreement (for employees) (filed as Exhibit 10.16 to the Company’s Registration Staten
10.8	**	Form of Restricted Stock Agreement (for non-officer employees) (filed as Exhibit 10.36 to the Company’s Annual
10.9	**	Form of Restricted Stock Agreement (for non-employee directors) (filed as Exhibit 10.18 to the Company’s Annua
10.10	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Timothy A. Leach (filed
10.11	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and E. Joseph Wright (filed a
10.12	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Darin G. Holderness (file
10.13	**	Employment Agreement dated December 19, 2008, between Concho Resources Inc. and Matthew G. Hyde (filed a
10.14	**	Employment Agreement dated November 5, 2009, between Concho Resources Inc. and C. William Giraud (filed a
10.15	**	Employment Agreement dated March 19, 2014, between Concho Resources Inc. and Jack F. Harper (filed as Exhi
10.16	**	Form of First Amendment to Employment Agreement between Concho Resources Inc. and each of Messrs. Leach
10.17	**	Form of Indemnification Agreement between Concho Resources Inc. and each of the officers and directors thereof
10.18	**	Indemnification Agreement, dated February 27, 2008, by and between Concho Resources, Inc. and William H. Ea
10.19	**	Indemnification Agreement, dated May 21, 2008, by and between Concho Resources, Inc. and Matthew G. Hyde (
10.20	**	Indemnification Agreement, dated August 25, 2008, by and between Concho Resources, Inc. and Darin G. Holder
10.21	**	Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and Mark B. Pucke
10.22	**	Indemnification Agreement, dated November 5, 2009, by and between Concho Resources, Inc. and C. William Gi
10.23	**	Form of Director and Officer Indemnification Agreement between Concho Resources Inc. and each Messrs. Surma
10.24	**	Indemnification Agreement, dated January 10, 2012, between Concho Resources Inc. and Gary A. Merriman (filed
10.25		Amended and Restated Credit Agreement, dated July 31, 2008, by and among Concho Resources Inc., JP Morgan
10.26		First Amendment to Amended and Restated Credit Agreement dated as of April 7, 2009, to the Amended and Rest
10.27		Limited Consent and Waiver, dated September 4, 2009, to the Amended and Restated Credit Agreement dated July
10.28		Second Amendment to Amended and Restated Credit Agreement, dated April 26, 2010, by and among Concho Re
10.29		Third Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated June 16, 2010, among
10.30		Fourth Amendment to Amended and Restated Credit Agreement, dated October 7, 2010, among Concho Resource

10.31		Fifth Amendment to Amended and Restated Credit Agreement and Limited Waiver, dated as of December 7, 2010
10.32		Sixth Amendment to Amended and Restated Credit Agreement, dated as of April 25, 2011, among Concho Resour
10.33		Seventh Amendment to Amended and Restated Credit Agreement, dated as of October 12, 2011, among Concho R
10.34		Eighth Amendment to Amended and Restated Credit Agreement, dated as of April 12, 2012, among Concho Resou
10.35		Ninth Amendment to Amended and Restated Credit Agreement, dated as of May 31, 2012, among Concho Resour
10.36		Tenth Amendment to Amended and Restated Credit Agreement, dated as of October 26, 2012, among Concho Res
10.37		Eleventh Amendment to Amended and Restated Credit Agreement, dated as of April 15, 2013, among Concho Res
10.38		Twelfth Amendment to Amended and Restated Credit Agreement, dated as of October 29, 2013, among Concho R
10.39		Second Amended and Restated Credit Agreement, dated as of May 9, 2014, among Concho Resources Inc., the len
10.40		Registration Rights Agreement dated February 27, 2006, among Concho Resources Inc. and the other signatories t
12.1	(a)	Ratio of Earnings to Fixed Charges and Ratio of Earnings to Fixed Charges and Preferred Stock Dividends.
21.1	(a)	Subsidiaries of Concho Resources Inc.
23.1	(a)	Consent of Grant Thornton LLP.
23.2	(a)	Consent of Netherland, Sewell & Associates, Inc.
23.3	(a)	Consent of Cawley, Gillespie & Associates, Inc.
31.1	(a)	Certification of Chief Executive Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
31.2	(a)	Certification of Chief Financial Officer pursuant to Section 302 of the Sarbanes-Oxley Act of 2002.
32.1	(b)	Certification of Chief Executive Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
32.2	(b)	Certification of Chief Financial Officer pursuant to Section 906 of the Sarbanes-Oxley Act of 2002.
99.1	(a)	Netherland, Sewell & Associates, Inc. Reserve Report.
99.2	(a)	Cawley, Gillespie & Associates, Inc. Reserve Report.
101.INS	(a)	XBRL Instance Document.
101.SCH	(a)	XBRL Schema Document.
101.CAL	(a)	XBRL Calculation Linkbase Document.
101.DEF	(a)	XBRL Definition Linkbase Document.
101.LAB	(a)	XBRL Labels Linkbase Document.
101.PRE	(a)	XBRL Presentation Linkbase Document.

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Index of Exhibits

(a) Filed herewith.

(b) Furnished herewith.

** Management contract or compensatory plan or agreement