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, 2015

OR

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

For the transition period from to

Commission File Number 001-32743

EXCO RESOURCES, INC.
(Exact name of registrant as specified in its charter)

Texas	**74-1492779**
(State or other jurisdiction of incorporation or organization)	**(I.R.S. Employer Identification No.)**
12377 Merit Drive **Suite 1700, LB 82** **Dallas, Texas**	**75251**
(Address of principal executive offices)	**(Zip Code)**

Registrant's telephone number, including area code: (214) 368-2084

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

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

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

None
(Title of class)

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. YES ☐ NO ☒

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. YES ☐ NO ☒

Indicate by check mark whether the registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. YES ☒ NO ☐

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate 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 is required to submit and post such files). YES ☒ NO ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§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 Form10-K or any amendment to this Form 10-K. ☒

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

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

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). YES ☐ NO ☒

As of February 25, 2016, the registrant had 282,924,079 outstanding common shares, par value $0.001 per share, which is its only class of common shares. As of the last business day of the registrant's most recently completed second fiscal quarter, the aggregate market value of the registrant's common shares held by non-affiliates was approximately $186,183,000.

DOCUMENTS INCORPORATED BY REFERENCE

Portions of the registrant's Definitive Proxy Statement on Schedule 14A to be furnished to shareholders in connection with its 2016 Annual Meeting of Shareholders are incorporated by reference in Part III, Items 10-14 of this Annual Report on Form 10-K.

EXCO RESOURCES, INC.

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Item 1. Business

General

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" are to EXCO Resources, Inc. and its consolidated subsidiaries.

We have provided definitions of terms commonly used in the oil and natural gas industry in the "Glossary of selected oil and natural gas terms" beginning on page 26.

We are an independent oil and natural gas company engaged in the exploration, exploitation, acquisition, development and production of onshore U.S. oil and natural gas properties with a focus on shale resource plays. Our principal operations are conducted in certain key U.S. oil and natural gas areas including Texas, Louisiana and the Appalachia region.

As of December 31, 2015, our Proved Reserves were approximately 907.3 Bcfe, of which 86% were natural gas and 48% were Proved Developed Reserves. As of December 31, 2015, the PV-10 and Standardized Measure of our Proved Reserves were approximately $402.1 million. For the year ended December 31, 2015, we produced 124.0 Bcfe of oil and natural gas.

Our business strategy

Our primary strategy focuses on the exploitation and development of our shale resource plays and the pursuit of leasing and acquisition opportunities. We plan to carry out this strategy by executing on a strategic plan that incorporates the following three core objectives: (i) restructuring the balance sheet to enhance our business and extend structural liquidity; (ii) transforming EXCO into the lowest cost producer; and (iii) optimizing and repositioning the portfolio. We believe this strategy will allow us to create long-term value for our shareholders. The three core objectives and the Company's recent progress are detailed below:

Restructuring the balance sheet to enhance our business and extend structural liquidity

We are focused on improving our capital structure and providing structural liquidity. In the fourth quarter of 2015, we executed a series of transactions that resulted in the issuance of senior secured second lien term loans and utilized the proceeds to reduce indebtedness under our credit agreement ("EXCO Resources Credit Agreement"), 7.5% senior unsecured notes due September 15, 2018 ("2018 Notes") and 8.5% senior unsecured notes due April 15, 2022 ("2022 Notes"). The senior secured second lien term loans are due on October 26, 2020 and bear interest at a rate of 12.5% per annum ("Second Lien Term Loans"). Additionally, in the fourth quarter of 2015, we repurchased $40.8 million in principal of the 2018 Notes through open market purchases with $12.0 million in cash. These transactions and our operations enhanced our balance sheet and increased our financial flexibility, including the accomplishment of the following results during the year ended December 31, 2015:

- reduced the principal amount of total outstanding indebtedness by $304.2 million, or 21%;
- reduced the principal amount of outstanding senior unsecured notes by $869.2 million, or 70%;
- reduced the principal amount of the nearest unsecured debt maturity, due in 2018, by $592.0 million, or 79%; and
- extended the weighted average debt maturity.

Our liquidity was $334.4 million as of December, 31, 2015 and we have approximately $125.0 million of additional liens capacity that can be utilized for future exchanges or issuances of secured indebtedness. Since December 31, 2015, we have purchased an additional $9.5 million of 2018 Notes and $39.9 million of 2022 Notes with $6.7 million in cash. The 2018 Notes and 2022 Notes repurchased will be canceled by the trustee following customary settlement procedures. We are currently evaluating additional balance sheet restructuring transactions including the issuance of additional indebtedness, the restructuring or repurchase of existing indebtedness, issuance of equity or divestitures of assets.

We continued to reduce costs through the restructuring of our commercial contracts, including the renegotiation of firm transportation and sales contracts in the North Louisiana and South Texas regions. In North Louisiana, we were able to improve our rate per Mcf of natural gas in exchange for extending the term of the contracts. In South Texas, we were able to improve our realized price per barrel of oil with our primary purchaser. We remain committed to restructuring our gathering and transportation contracts with our midstream providers.

Transforming EXCO into the lowest cost producer

We have implemented several initiatives to reduce our general and administrative costs and lease operating costs, including significant reductions in our workforce. As a result of the reductions in force, our total employee count decreased to 315 persons at December 31, 2015, which represents a 44% decrease compared to December 31, 2014 and a 58% decrease compared to December 31, 2013. The general and administrative cost saving initiatives also included reductions in benefits, office expenses, software licenses and other costs. As such, we expect our general and administrative expenses and lease operating expenses to continue to decrease in 2016 as we realize a full year of cost savings from the reduction in force and other initiatives.

Our operational team is dedicated to the continuous improvement and innovation of well designs in order to maximize our return on capital. The drilling program in the Shelby area of East Texas was the focal point of our 2015 capital program and we achieved strong results in both the Haynesville and Bossier shales based on our enhanced completion methods. The enhanced completion methods included higher levels of proppant, longer laterals and other optimizations to our completion design. The improved well performance in the East Texas region resulted in an increase in the EUR to 1.5 Bcf per 1,000 lateral feet for certain proved undeveloped Haynesville and Bossier shale locations compared to 1.3 Bcf per 1,000 lateral feet as of December 31, 2014. We plan to apply similar completion methods in the development of our Haynesville shale assets in the North Louisiana region during 2016. These enhanced well designs and completion methods also resulted in an increase in the EUR to 2.0 Bcf per 1,000 lateral feet for certain proved undeveloped Haynesville shale locations in the Holly area of North Louisiana from 1.6 Bcf per 1,000 lateral feet as of December 31, 2014. We have been able to reduce drilling and completion costs across all regions through modifications to well designs, renegotiated contracts with vendors, and other efficiencies. We have also seen sustained performance improvements in North Louisiana from the implementation of a full field compression program, which is expected to flatten our base decline and reduce future capital requirements.

Optimizing and repositioning the portfolio

We have implemented a disciplined capital allocation approach to ensure the highest and best use of capital. Our use of capital is allocated based on the highest risk adjusted rates of return, including both the development of our oil and natural gas properties and liability management initiatives. Our development program during the first six months of 2016 is focused on natural gas drilling and completion activities in North Louisiana that achieve the highest rates of return in our portfolio.

We focus on allocating capital to our drilling program to generate value by increasing our drilling inventory through leasing and acquisitions. We continue to evaluate opportunities to add undeveloped locations in core areas that meet our strategic objectives at a low cost. We are able to leverage our technical expertise and economies of scale to maximize our returns in these areas. We will also evaluate divestitures of assets that would allow us to redeploy capital to projects with higher rates of return.

Our strengths

High quality asset base in attractive regions

Our core areas have an extensive inventory of drilling opportunities which includes a diverse portfolio of both oil and natural gas assets that provide us the option to allocate capital to enhance our returns in various commodity price environments. In addition, a significant portion of our acreage is held-by-production which allows us to develop these properties within an optimum time frame. We hold significant acreage positions in three prominent shale plays in the United States:

- East Texas and North Louisiana - we currently hold approximately 83,800 net acres in the Haynesville and Bossier shales;
- South Texas - we currently hold approximately 65,800 net acres in the Eagle Ford shale; and
- Appalachia - we currently hold approximately 137,400 net acres prospective for the Marcellus shale.

Our properties are generally characterized by:

- multi-year inventory of development drilling and exploitation projects;
- high drilling success rates;
- significant unproved reserves and resources; and
- long reserve lives.

We have extensive amounts of technical and operational expertise within the Haynesville and Bossier shales. We have accumulated significant amounts of contiguous acreage and are one of the largest operators within this region. Our economies of scale and operational expertise have allowed us to efficiently develop our assets and minimize our costs through greater utilization of multi-well pads and existing infrastructure and facilities.

We have applied our technical and operational expertise from other shale plays to our development of the Eagle Ford shale. We have realized significant improvements in our drilling performance and the optimization of our well design has yielded strong results. Our position includes producing properties and undeveloped locations in the Eagle Ford shale, Buda and other formations.

Our position in the Marcellus shale requires low maintenance capital as a substantial portion of our acreage is held-by-production, which gives us flexibility to control the timing of our development activities in the region.

Operational control

We operate a significant portion of our properties which allows us to manage our operating costs and better control capital expenditures as well as the timing of development and exploitation activities. Therefore, we are able to allocate our capital to the most attractive projects based on commodity prices, rates of return and industry trends. As of December 31, 2015, we operated 6,380 of our 6,891 gross wells, or wells representing approximately 95% of our Proved Developed Reserves. We have continued to demonstrate improved drilling and completion results in our operated areas while maintaining low capital and operating costs.

Skilled technical personnel and experienced team

We have developed a workforce of highly skilled technical and operational personnel who have been successful in developing our shale resources. We leverage our technical expertise to exploit our asset base in an efficient and cost-effective manner. We believe our technical expertise gives us a competitive advantage in our key operating areas.

Our management team has extensive industry experience in acquiring, exploring, exploiting and developing oil and natural gas properties. We entered into a services and investment agreement with Energy Strategic Advisory Services LLC ("ESAS"), a wholly-owned subsidiary of Bluescape Resources Company LLC (“Bluescape”), during 2015 to assist in the development and execution of our business plan. The ESAS team has extensive experience in developing and executing effective business strategies and complements the operating and financial capabilities of our management team. We believe that we will be able to capitalize on the strengths of these teams, which will be instrumental in executing a disciplined approach to accomplish our business strategies.

Plans for 2016

Our plans for 2016 focus primarily on the exploitation and development of the Haynesville shale in the Holly area in North Louisiana and the Haynesville and Bossier shales in the Shelby area of East Texas. We believe the capital projects included in our plans for 2016 provide attractive returns in the current depressed commodity price environment. We will continue to focus on operational initiatives to enhance our well designs, optimize our base production and maximize the recoveries from our properties. We will continue to focus on fiscal discipline, including the continuation of our operating and general and administrative cost reduction efforts. Furthermore, we will continue to evaluate and pursue transactions to enhance our financial flexibility and preserve our liquidity.

Summary of geographic areas of operations

The following tables set forth summary operating information attributable to our principal geographic areas of operation as of December 31, 2015:

Areas	Total Proved Reserves (Bcfe) (1)	PV-10 (in millions) (1) (2)	Average daily net production (Mmcfe) (3)
North Louisiana	485.2	$ 91.1	167
East Texas	240.5	97.9	63
South Texas	129.5	206.9	44
Appalachia and other	52.1	6.2	37
Total	907.3	$ 402.1	311

Areas	Total gross acreage	Total net acreage
North Louisiana	102,800	51,500
East Texas	120,200	46,100
South Texas (4)	117,500	65,800
Appalachia and other	607,800	272,800
Total	948,300	436,200

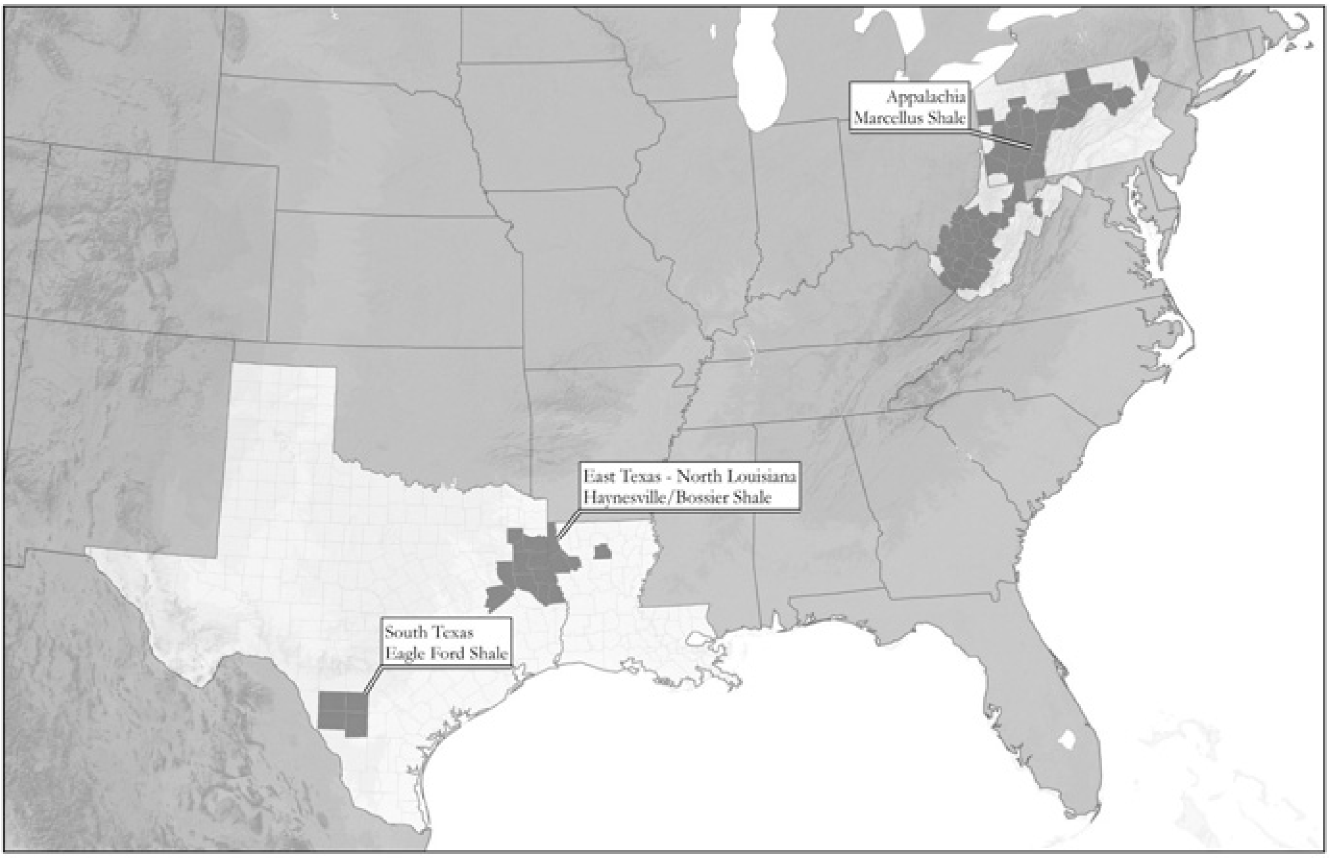
(1) The total Proved Reserves and PV-10 as of December 31, 2015 were prepared in accordance with the rules and regulations of the Securities and Exchange Commission ("SEC"). The estimated future plugging and abandonment costs necessary to compute PV-10 were computed internally.

(2) The PV-10 data used in this table was based on reference prices using the simple average of the spot prices for the trailing 12 month period using the first day of each month beginning on January 1, 2015 and ending on December 1, 2015, of $2.59 per Mmbtu for natural gas and $50.28 per Bbl for oil, in each case adjusted for geographical and historical differentials. Market prices for oil and natural gas are volatile (see “Item 1A. Risk Factors-Risks Relating to Our Business”). We believe that PV-10, while not a financial measure in accordance with generally accepted accounting principles in the United States ("GAAP"), is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions due to tax characteristics which can differ significantly among comparable companies. The total Standardized Measure, a measure recognized under GAAP, as of December 31, 2015 was $402.1 million. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with the Financial Accounting Standards Board ("FASB") Accounting Standards Codification ("ASC") 932, *Extractive Activities, Oil and Gas* ("ASC 932"). Our existing net operating loss carryforwards eliminated estimated future income taxes for the year ended December 31, 2015. The amount of estimated future plugging and abandonment costs, the PV-10 of these costs and the Standardized Measure were determined by us. We do not designate our derivative financial instruments as hedges and accordingly, do not include the impact of derivative financial instruments when computing the Standardized Measure.

(3) The average daily net production rate was calculated based on the average daily rate during the final month of the year ended December 31, 2015. The 37 Mmcfe per day for Appalachia and other excludes shut-in volumes of approximately 13 Mmcfe per day as a result of low commodity prices in the region.

(4) The acreage in this region includes 38,500 net acres outside of our core area in Zavala County that are subject to our joint venture partner's right to participate in each proposed well. The acreage outside of our core area is not subject to the participation agreement with our joint venture partner ("Participation Agreement").

Our development and exploitation project areas



East Texas and North Louisiana

Our operations in East Texas and North Louisiana are focused on the Haynesville and Bossier shales which are primarily located in Shelby, San Augustine and Nacogdoches Counties in Texas and DeSoto and Caddo Parishes in Louisiana. Our acreage in this region is predominantly held-by-production. The Haynesville shale is located at depths of 12,000 to 14,500 feet and is being developed with horizontal wells that typically have 4,300 to 7,500 foot laterals. The Bossier shale lies just above certain portions of the Haynesville shale and also contains rich deposits of natural gas. The geographic position of our properties in the Haynesville and Bossier shales provides us access to nearby markets with favorable natural gas price indices compared to the rest of the country.

The Company entered 2015 with three operated rigs drilling in the Holly area of North Louisiana and subsequently moved these rigs to the Shelby area of East Texas. We released one of these rigs and moved the other two rigs to resume drilling in North Louisiana in early 2016. Our development activities in North Louisiana during 2016 will feature a modified Haynesville shale well design which includes enhanced completion methods that have proven to be successful in our East Texas region, including the use of more proppant, modified well spacing and longer laterals.

North Louisiana Holly area

Our position in the Holly area consists of 29,200 net acres in DeSoto Parish and 8,600 net acres in Caddo Parish, which are all held-by-production. At December 31, 2015, we had a total of 413 gross (205.9 net) operated horizontal wells flowing to sales. We drilled 2 gross (1.7 net) operated wells and turned-to-sales 18 gross (11.9 net) operated wells in the Haynesville shale during the first half of 2015 based on standard lateral lengths and completion designs. We turned-to-sales a test well in the Bossier shale in DeSoto Parish in the 2015 using a restricted flowback methodology and will continue to evaluate the potential for further development. Including non-operated volumes, our average natural gas production was approximately 167 net Mmcfe per day during December 2015. We plan to operate an average of two drilling rigs to drill 9 gross (5.5 net) wells during the first six months of 2016 and complete those wells during 2016. The average lateral lengths on the wells drilled and completed during 2016 will range from 4,500 to 7,500 feet. The development in the North Louisiana region during 2016 will feature these enhanced completion methods that have proven to be effective in our East Texas region. The enhanced well designs and completion methods resulted in an increase of the EUR to 2.0 Bcf per 1,000 lateral feet as of December 31, 2015 for certain proved undeveloped Haynesville shale locations in our Holly area of North Louisiana, compared to 1.6 Bcf per 1,000 lateral feet as of December 31, 2014.

North Louisiana operating effectiveness

We have implemented several initiatives to enhance and manage our base production in the region. This includes a full field compression program, foamer injection program and the installation of artificial lift. We entered into a contract with our midstream service provider for additional compression services in the Holly area which began in late 2015. We have seen sustained performance improvement from these initiatives as evidenced by a flattening of our base production decline by lowering the overall gathering system pressure from approximately 1,185 psi to a target of 500 psi. The lower gathering pressure allows the artificial lift and foamer injection to be more efficient, which flattens our base decline and reduces future capital requirements.

East Texas Shelby Area

Our operations in East Texas are focused on the Haynesville and Bossier shales. Our acreage is primarily located in Harrison, Panola, Shelby, San Augustine and Nacogdoches Counties in Texas and is predominantly held-by-production. The Haynesville and Bossier shales in East Texas are being developed with horizontal wells that typically have 6,000 to 7,500 foot laterals. Our position in the Shelby area primarily consists of 31,400 net acres and includes a portion that is subject to continuous drilling obligations. We plan to drill on the acreage subject to the continuous drilling obligation in the future to hold the acreage. Excluding the acreage subject to the continuous drilling obligation, approximately 88% of our net acres are held-by-production in the Shelby area. As of December 31, 2015, we had a total of 97 gross (43.6 net) operated horizontal wells flowing to sales. We drilled 21 gross (10.0 net) wells in the area during 2015, which included 10 gross (4.6 net) operated wells in the Haynesville shale and 11 gross (5.4 net) operated wells in the Bossier shale.

The wells turned-to-sales in this region during 2015 featured enhanced completion methods that continue to yield strong results. These methods have included the use of more than 2,700 lbs of proppant per lateral foot on certain wells. The improved well performance in the East Texas region resulted in an increase in the EUR to 1.5 Bcf per 1,000 lateral feet for certain proved undeveloped Haynesville and Bossier shale locations compared to 1.3 Bcf per 1,000 lateral feet as of December 31, 2014. Including non-operated volumes, our average natural gas production was approximately 63 net Mmcfe per day during December 2015. Our development in East Texas during the first six months of 2016 will focus on completing and turning to sales 9 gross (4.1 net) wells drilled in 2015.

East Texas operating effectiveness

In the East Texas region, our average drilling and completion costs decreased from $12.1 million per well in 2014 to $11.6 million per well in 2015 despite longer laterals and the use of more proppant in the completion phase. The decrease is primarily a result of increased drilling efficiency as we moved from an appraisal mode to a manufacturing mode. This included reductions in road and location costs through the utilization of multi-well pad sites and lower mobilization costs due to closer proximity between well sites. We achieved improved drilling times during 2015, including drilling a Haynesville shale well in 35 days to a total measured depth of 19,860 feet and we recently completed a Haynesville shale well in Nacogdoches County, Texas with a total measured depth of 21,289 feet, the longest in the Company's history. The average lateral length for the wells drilled and completed in 2015 was 6,900 feet and represent some of our longest laterals drilled-to-date in the region.

South Texas

Our position in this region includes 65,800 net acres, of which approximately 81% is held-by-production, that cover portions of Zavala, Dimmit and Frio Counties in Texas. Our acreage in the Eagle Ford shale is in the oil window and averages 375 feet in gross thickness at true vertical depths ranging from 5,400 to 6,800 feet. Our lateral lengths average 7,400 feet and range from 5,000 to 9,000 feet and the total measured depth averages 14,600 feet. Our acreage in the area also includes additional upside in formations such as the Austin Chalk, Buda and Pearsall formations.

As of December 31, 2015, we had a total of 235 gross (112.7 net) operated horizontal wells flowing to sales. We drilled 10 gross (2.8 net) wells and turned-to-sales 33 gross (7.7 net) wells in the Eagle Ford shale during the year ended December 31, 2015. The most recent Eagle Ford shale wells turned-to-sales featured enhanced completion methods, including longer laterals and more proppant, and have provided our best results to date in the region. In the Buda formation, we drilled and turned-to-sales 4 gross (3.3 net) wells and participated in 3 gross (0.5 net) during the year ended December 31, 2015. Including non-operated volumes, our average oil production in South Texas was approximately 6,500 net barrels of oil per day during December 2015. Our plans for 2016 do not include any development in this region as a result of low oil prices.

South Texas operational effectiveness

We have utilized our expertise from other shale developments and have realized significant operational efficiencies in our Eagle Ford assets. This includes improved drilling times per well in the Eagle Ford shale and decreased average drilling and completion costs from $7.1 million per well in 2014 to $5.7 million per well in 2015 despite longer laterals and the use of more proppant in the completion phase.

There are third-party operated central production facilities connected to the wells in our core area and a pipeline from the facilities to an oil pipeline in Dilley, Texas. This infrastructure allows us to increase the efficiency of our production and reduce costs associated with wells in our core area. We are evaluating the design of an electrical distribution network over the core development area that could provide a more efficient cost structure to operate the field. We were also able to significantly reduce our operating costs in the region during 2015 through the execution of several initiatives such as reductions in service costs with certain key vendors, including rental equipment and chemical treating programs. In addition, we successfully renegotiated a sales contract in this region during 2015 which improved our net realized price for the related oil production.

Appalachia

Our operations in the Appalachia region have primarily included testing and selectively developing the Marcellus shale with horizontal drilling while maintaining our existing conventional production from shallow vertical wells. We currently hold approximately 269,800 net acres in the Appalachian basin, with approximately 137,400 of these net acres prospective for the Marcellus shale. As of December 31, 2015, we had a total of 5,509 gross (2,626.9 net) operated vertical shallow wells flowing to sales with an average production rate of approximately 11 net Mmcfe per day. As of December 31, 2015, we operated a total of 126 gross (46.2 net) horizontal wells in the Marcellus shale with an average production rate of approximately 25 net Mmcfe per day. During 2015, we proactively shut-in wells in the Marcellus shale due to low regional gas prices which resulted in 1.1 Bcfe of shut-in production for the year. Including non-operated volumes, our production in the Appalachia region was approximately 37 net Mmcfe per day during December 2015, which excludes shut-in volumes of approximately 13 Mmcfe per day as a result of low commodity prices in the region.

Our Pennsylvania acreage encompasses 22 counties. Drilling, completion and production activities target the Marcellus shale as well as the Upper Devonian, Venanago, Bradford and Elk sandstone groups at depths ranging from 1,800 to more than 12,000 feet. Our West Virginia area includes 27 counties and stretches from the northern to the southern areas of the state. Drilling, completion and production activities target the Marcellus shale and multiple reservoirs of the Mississippian and Devonian formations found at depths ranging from 1,500 to 8,100 feet. A portion of our acreage in the Appalachia region is prospective for the Utica shale and we are currently assessing its potential.

Marcellus shale

We suspended our drilling program in this region in response to low realized natural gas prices from the widening of regional price differentials to focus on projects with higher rates of return. Approximately 84% of our acreage is held-by-production, which allows us to control the timing of the development of this region. In 2015, we turned-to-sales 1 gross (0.5 net) operated appraisal well in Clinton County targeting the Marcellus shale. In 2016, we have plans to connect and turn to sales 1 gross (0.5 net) appraisal well to sales in Lycoming County, Pennsylvania. We have an extensive inventory of undeveloped locations prospective for the Marcellus shale that would provide attractive rates of return in an improved commodity price environment.

Marcellus shale operational effectiveness

We have effectively managed our base production declines as a result of increased automation and surveillance equipment to reduce downtime as well as artificial lift installations. We also implemented a reduction in force, reducing our field employee count in the area by 41% from 147 employees as of December 31, 2014 to 87 employees as of December 31, 2015. As a result of this reduction in force, we restructured our field organization to better align the operations personnel with the asset base and reduce our operating costs.

Company-wide operational effectiveness

The current commodity price environment resulted in the reduction of service costs, such as rig and completion service contracts, throughout the industry. We will remain focused on reducing our well costs attributable to drilling while continuing to optimize our completions. We have continued to improve our well design by increasing the amount of proppant used in the hydraulic fracturing process on recent completions. These changes in our well design have improved our well performance and EUR.

Our production operations team is focused on lowering our direct operating costs, including water management, efficient utilization of our personnel, equipment rentals and chemicals. As a result of the current commodity price environment, we have negotiated significant reductions in service costs with vendors. Through the use of automation at well sites, we can better utilize company personnel time to perform maintenance work and reduce the use of third party services. We also have an operations tracking database system in place that enables us to be proactive in maintenance and repairs which results in cost efficiencies and minimizes production downtime. We plan to continue to efficiently manage our chemical programs which will allow us to reduce costs by minimizing well intervention work.

We have a Dallas-based operations control center that is staffed 24 hours a day that monitors our Haynesville, Bossier, Eagle Ford and Marcellus shale wells. This control system gives us the ability to monitor and control natural gas flow over a large portion of our fields, which allows us to optimize the daily natural gas flow from our assets and minimize downtime.

Our hydraulic fracturing activities

Oil and natural gas may be recovered from our properties through the use of sophisticated drilling and hydraulic fracturing techniques. Hydraulic fracturing involves the injection of water, sand, gel and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Our hydraulic fracturing activities are primarily focused in the Eagle Ford shale in South Texas, Haynesville and Bossier shales in East Texas and North Louisiana and Marcellus shale in the Appalachia region. Predominantly all of our Proved Reserves are associated with shale assets in these areas.

Although the cost of each well will vary, the costs associated with hydraulic fracturing activities on average represent the following portions of the total costs of drilling and completing a well: 30-40% in the Haynesville and Bossier shale formation; 30-40% in the Eagle Ford shale formation; and 25-35% in the Marcellus shale formation.

We review best practices and industry standards to comply with regulatory requirements in the protection of potable water sources when drilling and completing our wells. Protective practices include, but are not limited to, setting multiple strings of protection pipe across potable water sources and cementing these pipe strings to surface, continuously monitoring the hydraulic fracturing process in real time and disposing of non-recycled produced fluids in authorized disposal wells at depths below the potable water sources. In addition, we actively seek methods to minimize the environmental impact of our hydraulic fracturing operations in all of our operating areas. For example, we use discharge water from a local paper plant as a key water source for our fracture stimulation operations in North Louisiana. We recycle flowback fluids when economically feasible.

For more information on the risks of hydraulic fracturing, see “Item 1A. Risk Factors-Our business exposes us to liability and extensive regulation on environmental matters, which could result in substantial expenditures” and “Item 1A. Risk Factors-Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.”

Our oil and natural gas reserves

Our Proved Reserves as of December 31, 2015 were approximately 907.3 Bcfe, of which approximately 97% were related to our shale properties. Of our Proved Reserves attributed to shale properties, approximately 82% were located in the Haynesville/Bossier shales, 15% in the Eagle Ford shale and 3% in the Marcellus shale. Our non-shale Proved Reserves represented approximately 3% of total Proved Reserves as of December 31, 2015, which consisted primarily of conventional assets in the Appalachia region.

The following table summarizes Proved Reserves as of December 31, 2015, 2014 and 2013.   This information was prepared in accordance with the rules and regulations of the SEC. The comparability of our reserves is impacted by purchases and sales of reserves in place, production, revisions of previous estimates and discoveries and extensions. See "Management's discussion and analysis of oil and natural gas reserves" for a summary of the changes in our Proved Reserves.

	As of December 31,		
	2015	2014	2013
Oil (Mbbls)			
Developed	12,056	14,429	11,274
Undeveloped	8,383	3,258	4,104
Total	20,439	17,687	15,378
Natural gas (Mmcf) (1)			
Developed	364,932	504,636	669,644
Undeveloped	419,742	653,038	362,333
Total	784,674	1,157,674	1,031,977
Equivalent reserves (Mmcfe)			
Developed	437,268	591,210	737,291
Undeveloped	470,040	672,586	386,954
Total	907,308	1,263,796	1,124,245
PV-10 (in millions) (2)			
Developed	$ 359.4	$ 1,117.6	$ 1,153.5
Undeveloped	42.7	425.0	98.8
Total	$ 402.1	$ 1,542.6	$ 1,252.3
Standardized Measure (in millions) (3)	$ 402.1	$ 1,542.6	$ 1,252.3

(1) Beginning in 2015, we began reporting our natural gas liquids ("NGLs") as a component of natural gas since NGLs are not considered to be significant. Primarily all of our prior period NGLs were associated with properties owned by Compass, which EXCO divested in 2014. Prior period information has been conformed to be consistent with current period information.

(2) The PV-10 is based on the following average spot prices, in each case adjusted for historical differentials. Prices presented on the table below are the trailing 12 month simple average spot price at the first of the month for natural gas at Henry Hub and West Texas Intermediate crude oil at Cushing, Oklahoma.

	Average spot prices	
	Oil (per Bbl)	Natural gas (per Mmbtu)
December 31, 2015	$ 50.28	$ 2.59
December 31, 2014	94.99	4.35
December 31, 2013	96.78	3.67

(3) There is no difference in Standardized Measure and PV-10 for all years presented as the impacts of net operating loss carry-forwards eliminated future income taxes.

We believe that PV-10, while not a financial measure in accordance with GAAP, is an important financial measure used by investors and independent oil and natural gas producers for evaluating the relative significance of oil and natural gas properties and acquisitions due to tax characteristics, which can differ significantly among comparable companies. The Standardized Measure represents the PV-10 after giving effect to income taxes, and is calculated in accordance with ASC 932.

Management has established, and is responsible for, internal controls designed to provide reasonable assurance that the estimates of Proved Reserves are computed and reported in accordance with rules and regulations promulgated by the SEC as well as established industry practices used by independent engineering firms and our peers. These internal controls include documented process workflows, qualified professional engineering and geological personnel with specific reservoir experience. Our internal audit function routinely tests our processes and controls. We also retain outside independent engineering firms to prepare or audit estimates of our Proved Reserves. Senior management reviews and approves our reserve estimates, whether prepared internally or by third parties. Our Vice President of Engineering and Geoscience oversees our outside independent engineering firms, Lee Keeling and Associates, Inc. ("Lee Keeling"), Netherland, Sewell & Associates, Inc. ("NSAI"), and Ryder Scott Company, L.P. ("Ryder Scott") in connection with the preparation of their estimates of our Proved Reserves or their audit of the Proved Reserves prepared by EXCO's internal engineers. We also regularly communicate with our outside independent engineering firms throughout the year regarding technical and operational matters critical to our reserve estimations. Our Vice President of Engineering and Geoscience is a registered Professional Engineer in the state of Texas with over 34 years of experience in the oil and natural gas industry. He is a graduate of Texas A&M University with a degree in Petroleum Engineering. Our Chief Operating Officer and our Vice President of Engineering and Geoscience, with input from other members of senior management, are responsible for the selection of our third-party engineering firms and receive the reports generated by such firms. The third-party engineering reports are also provided to our audit committee.

The estimates of Proved Reserves and future net cash flows for our non-shale properties as of December 31, 2015, 2014 and 2013 have been prepared by Lee Keeling. Our estimated Proved Reserves and future net cash flows for our shale properties in the South Texas region were prepared by Ryder Scott as of December 31, 2015, 2014 and 2013. Our estimated Proved Reserves and future net cash flows for our shale properties in all regions except South Texas were prepared by NSAI as of December 31, 2015 and 2014 and were prepared by our internal engineers and audited by NSAI as of December 31, 2013. Lee Keeling, NSAI and Ryder Scott are independent petroleum engineering firms that perform a variety of reserve engineering and valuation assessments for public and private companies, financial institutions and institutional investors. Lee Keeling, NSAI and Ryder Scott have performed these services for over 50 years. Our internal technical employees responsible for reserve estimates and interaction with our independent engineers include corporate officers with petroleum and other engineering degrees, professional certifications and industry experience similar to those of our independent engineering firms.

Estimates of oil and natural gas reserves are projections based on a process involving an independent third party engineering firm's communication with EXCO's engineers and geologists, the collection of any and all required geological, geophysical, engineering and economic data, and such firm's complete external preparation of all required estimates and are forward-looking in nature. These reports rely on various assumptions, including definitions and economic assumptions required by the SEC, including the use of constant oil and natural gas pricing, use of current and constant operating costs and capital costs. We also make assumptions relating to availability of funds and timing of capital expenditures for development of our Proved Undeveloped Reserves. These reports should not be construed as the current market value of our Proved Reserves. The process of estimating oil and natural gas reserves is also dependent on geological, engineering and economic data for each reservoir. Because of the uncertainties inherent in the interpretation of this data, we cannot ensure that the Proved Reserves will ultimately be realized. Our actual results could differ materially. See “Note 17. Supplemental information relating to oil and natural gas producing activities (unaudited)” in the Notes to our Consolidated Financial Statements for additional information regarding our oil and natural gas reserves and the Standardized Measure.

Lee Keeling, NSAI and Ryder Scott also examined our estimates with respect to reserve categorization, using the definitions for Proved Reserves set forth in SEC Regulation S-X Rule 4-10(a) and SEC staff interpretations and guidance. In preparing an estimate or performing an audit of our Proved Reserves and future net cash flows attributable to our interests, Lee Keeling, NSAI and Ryder Scott did not independently verify the accuracy and completeness of information and data furnished by us with respect to ownership interests, oil and natural gas production, well test data, historical costs of operation and development, product prices, or any agreements relating to current and future operations of the properties and sales of production. However, if in the course of the examination anything came to the attention of Lee Keeling, NSAI or Ryder Scott which brought into question the validity or sufficiency of any such information or data, Lee Keeling, NSAI or Ryder Scott did not rely on such information or data until they had satisfactorily resolved their questions relating thereto or had independently verified such information or data. Lee Keeling, NSAI and Ryder Scott determined that their estimates of Proved Reserves or our audited estimates of Proved Reserves conform to the guidelines of the SEC, including the criteria of Reasonable Certainty, as it pertains to expectations about the recoverability of Proved Reserves in future years, under existing economic and operating conditions, consistent with the definition in Rule 4-10(a)(24) of SEC Regulation S-X.

Management's discussion and analysis of oil and natural gas reserves

The following discussion and analysis of our proved oil and natural gas reserves and changes in our Proved Reserves is intended to provide additional guidance on the operational activities, transactions, economic and other factors which significantly impacted our estimate of Proved Reserves as of December 31, 2015 and changes in our Proved Reserves during 2015. This discussion and analysis should be read in conjunction with “Note 17. Supplemental information relating to oil and natural gas producing activities (unaudited)" and in "Item 1A. Risk Factors" addressing the uncertainties inherent in the estimation of oil and natural gas reserves elsewhere in this Annual Report on Form 10-K. The following table summarizes the changes in our Proved Reserves from January 1, 2015 to December 31, 2015.

	Oil (Mbbls)	Natural gas (Mmcf) (1)	Equivalent natural gas (Mmcfe)
Proved Developed Reserves	12,056	364,932	437,268
Proved Undeveloped Reserves	8,383	419,742	470,040
Total Proved Reserves	20,439	784,674	907,308
The changes in reserves for the year are as follows:			
January 1, 2015	17,687	1,157,674	1,263,796
Purchases of reserves in place	459	122	2,876
Discoveries and extensions	7,602	152,473	198,085
Revisions of previous estimates (2):			
Changes in price	(2,821)	(598,865)	(615,791)
Other factors	(145)	184,641	183,771
Sales of reserves in place	(1)	(1,445)	(1,451)
Production	(2,342)	(109,926)	(123,978)
December 31, 2015	20,439	784,674	907,308

(1) Beginning in 2015, we began reporting our NGLs as a component of natural gas. Primarily all of our prior period NGLs were associated with properties owned by Compass, which EXCO divested in 2014. Prior period information has been conformed to be consistent with current period information.

(2) Revisions of previous estimates include both reserves in place at the beginning of the year and acquisitions and divestitures, if any, during the year. We reclassified 223.0 Bcfe of Proved Undeveloped Reserves to unproved as a result of decreased commodity prices, which shortened the economic life of certain producing properties and resulted in the reclassification of Proved Undeveloped properties to unproved locations that became uneconomical when using prices prescribed by the SEC.

Purchases of reserves in place

Purchases of reserves in place consisted primarily of our acquisition of certain proved developed producing properties in South Texas in connection with the Participation Agreement. The reserve quantities attributable to purchases of reserves in place were calculated based on our estimates and assumptions as of the respective acquisition dates.

Discoveries and extensions

Proved Reserve additions from discoveries and extensions in 2015 were 198.1 Bcfe which were primarily due to 125.9 Bcfe, 47.5 Bcfe and 24.7 Bcfe of discoveries and extensions from our East Texas, South Texas and North Louisiana regions, respectively. The discoveries and extensions in the East Texas region were due to the development of our Shelby area and consist of both the Haynesville and Bossier shales. The discoveries and extensions in the South Texas region were the result of our Eagle Ford shale development. The discoveries and extensions in the North Louisiana region were due to the development of our Holly area focused on the Haynesville shale.

Revisions of previous estimates

Our revisions of previous estimates included downward revisions to our Proved Reserve quantities of 615.8 Bcfe as a result of decreased commodity prices, which shortened the economic life of certain producing properties and resulted in the reclassification of Proved Undeveloped properties to unproved locations that became uneconomical when using prices prescribed by the SEC. This change in price was primarily driven by the decrease in the trailing 12 month average of oil and natural gas prices. The trailing 12 month average oil price decreased from $94.99 per Bbl for the year ended December 31, 2014 to $50.28 per Bbl for the year ended December 31, 2015 and the trailing 12 month average natural gas price decreased from $4.35 per Mmbtu for the year ended December 31, 2014 to $2.59 per Mmbtu for the year ended December 31, 2015.

Our revisions of previous estimates also included 183.8 Bcfe upward revisions due to performance and other factors. This included 152.2 Bcfe of upward revisions in the North Louisiana region primarily due to modifications in the well design to incorporate more proppant and longer laterals. The upward revisions also included 36.7 Bcfe from our East Texas region primarily due to strong results in both the Haynesville and Bossier shales based on similar modifications in the well design which included higher levels of proppant, longer laterals and other optimizations to our completion design. The upward revision also reflects a reduction in capital costs and operating expenses, which extended the economic life of certain properties and resulted in upward revisions to our reserve quantities. As a result of the current commodity price environment, we have negotiated reductions in service costs with various vendors and have realized lower operating expenses primarily due to reductions in our workforce.

Oil and natural gas production

Total oil and natural gas production in 2015 was 124.0 Bcfe, which included approximately 8.4 Bcfe in production from extensions and discoveries that were not reflected in our Proved Reserves at January 1, 2015.

Proved Undeveloped Reserves

The following table summarizes the changes in our Proved Undeveloped Reserves, all of which are expected to be developed within five years, for the year ended December 31, 2015:

	Mmcfe
Proved Undeveloped Reserves at January 1, 2015	672,586
New discoveries and extensions (1)	145,556
Proved Undeveloped Reserves transferred to developed (2)	(73,372)
Proved Undeveloped Reserves transferred to unproved (3)	(222,960)
Other revisions of previous estimates of Proved Undeveloped Reserves (4)	(51,770)
Proved Undeveloped Reserves at December 31, 2015	470,040

(1) Approximately 62%, 25% and 13% of the discoveries and extensions of Proved Undeveloped Reserves in 2015 occurred in the East Texas, South Texas and North Louisiana regions, respectively. The discoveries and extensions in the East Texas region were due to the development of Haynesville and Bossier shales in the Shelby area which was the main focus of our 2015 development program.

(2) Approximately 85%, 9% and 6% of the Proved Undeveloped Reserves transferred to Proved Developed Reserves were in the North Louisiana, East Texas and South Texas regions, respectively. Capital costs incurred to convert Proved Undeveloped Reserves to Proved Developed Reserves were $76.5 million. The Proved Undeveloped Reserves transferred to Proved Developed Reserves in the North Louisiana region primarily relate to wells drilled in this region in 2014 that were completed in early 2015.

(3) This represents Proved Undeveloped Reserves reclassified to unproved as a result of decreased commodity prices, which shortened the economic life of certain producing properties and resulted in the reclassification of Proved Undeveloped properties to unproved locations that became uneconomical when using prices prescribed by the SEC. As a result of the decrease in commodity prices, we do not have any Proved Undeveloped Reserves in the Appalachia region as of December 31, 2015.

(4) The other revisions of previous estimates included downward revisions due to price of 232.1 Bcfe offset by upward revisions due to performance and other factors of 180.3 Bcfe. The revisions due to price related to decreased oil and natural gas prices. The revisions due to performance and other factors were primarily in the Haynesville shale in our North Louisiana region due to modifications in the well design to incorporate more proppant and longer laterals. In addition, as a result of the current commodity price environment, we have negotiated reductions in service costs with various vendors, which extended the economic life of certain properties and resulted in upward revisions to our reserve quantities.

Impacts of changes in reserves on depletion rate and statements of operations in 2015

Our depletion rate decreased to $1.72 per Mcfe in 2015 from $1.90 per Mcfe in 2014. The decrease was primarily due to the impairments of our oil and natural gas properties during 2015, which lowered our depletable base.

Our production, prices and expenses

The following table summarizes revenues, net production, average sales price per unit and costs and expenses associated with the production of oil and natural gas. Certain reclassifications have been made to prior period information to conform to current period presentation.

(in thousands, except production and per unit amounts)	Year Ended December 31, 2015	2014	2013
Revenues, production and prices:			
Oil:			
Revenue	$ 102,787	$ 196,316	$ 111,440
Production sold (Mbbls)	2,342	2,236	1,188
Average sales price per Bbl	$ 43.89	$ 87.80	$ 93.80
Natural gas:			
Revenue	$ 225,544	$ 463,953	$ 522,869
Production sold (Mmcf)	109,926	122,324	154,779
Average sales price per Mcf	$ 2.05	$ 3.79	$ 3.38
Costs and Expenses:			
Oil and natural gas operating costs per Mcfe	$ 0.43	$ 0.47	$ 0.38

We had two fields that exceeded 15% of our total Proved Reserves as of December 31, 2015. The Holly field in North Louisiana and Shelby field in East Texas represented approximately 53% and 26% of our total Proved Reserves, respectively. The following table provides additional information related to our Holly and Shelby fields:

	Year Ended December 31, 2015	2014	2013
Holly field:			
Natural gas production sold (Mmcf)	73,863	82,299	107,746
Average price per Mcf	$ 2.17	$ 4.02	$ 3.39
Oil and natural gas operating costs per Mcf	0.22	0.22	0.13
Shelby field:			
Natural gas production sold (Mmcf)	18,047	10,314	12,020
Average price per Mcf	$ 2.50	$ 3.90	$ 3.32
Oil and natural gas operating costs per Mcf	0.30	0.33	0.28

Our interest in productive wells

The following table quantifies information regarding productive wells (wells that are currently producing oil or natural gas or are capable of production), including temporarily shut-in wells. The number of total gross oil and natural gas wells excludes any multiple completions. Gross wells refer to the total number of physical wells in which we hold a working interest, regardless of our percentage interest. A net well is not a physical well, but is a concept that reflects the actual total working interests we hold in all wells. We compute the number of net wells by totaling the percentage interests we hold in all our gross wells.

	At December 31, 2015					
	Gross wells (1)			Net wells		
	Oil	Natural gas	Total	Oil	Natural gas	Total
Producing region:						
North Louisiana	—	608	608	—	217.6	217.6
East Texas	—	136	136	—	47.0	47.0
South Texas	250	4	254	114.0	1.6	115.6
Appalachia and other	339	5,554	5,893	164.8	2,543.4	2,708.2
Total	589	6,302	6,891	278.8	2,809.6	3,088.4

(1) As of December 31, 2015, we held interests in 1 gross well with multiple completions.

As of December 31, 2015, we operated 6,380 gross (3,035.3 net) wells, which represented approximately 95% of our Proved Developed Reserves.

Our drilling activities

Our drilling activities are primarily focused on horizontal drilling in shale plays, particularly in the Haynesville, Bossier, Eagle Ford and Marcellus shales. The following tables summarize our approximate gross and net interests in the operated wells we drilled during the periods indicated and refer to the number of wells completed during the period, regardless of when drilling was initiated. At December 31, 2015, we had 2 gross (0.7 net) wells being drilled and 7 gross (3.4 net) wells being completed or awaiting completion.

	Development wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2015 (1)	63	—	63	25.3	—	25.3
Year ended December 31, 2014	98	—	98	29.6	—	29.6
Year ended December 31, 2013	105	2	107	48.7	0.5	49.2

	Exploratory wells					
	Gross			Net		
	Productive	Dry	Total	Productive	Dry	Total
Year ended December 31, 2015 (1)	5	—	5	3.9	—	3.9
Year ended December 31, 2014	—	—	—	—	—	—
Year ended December 31, 2013 (2)	15	—	15	7.7	—	7.7

(1) Our development wells in 2015 included the Haynesville and Bossier shales in the Shelby area of East Texas and the Holly area of North Louisiana. Our development wells also included the Eagle Ford shale in our core area in Zavala and Frio Counties, Texas. We completed one gross exploratory well in the Bossier shale in the North Louisiana region and four gross exploratory wells in the Buda formation in the South Texas region.

(2) Exploratory wells in 2013 included certain wells drilled in the Eagle Ford shale under the farmout agreement outside of our core area in Zavala County, Texas and certain wells in the Marcellus shale in Jefferson, Clarion and Sullivan Counties, Pennsylvania.

Our developed and undeveloped acreage

Developed acreage includes those acres spaced or assignable to producing wells or wells capable of producing. Undeveloped acreage represents those acres that do not currently have completed wells capable of producing commercial quantities of oil or natural gas, regardless of whether the acreage contains Proved Reserves. The definitions of gross acres and net acres conform to how we determine gross wells and net wells. The following table sets forth our developed and undeveloped acreage:

	At December 31, 2015			
	Developed		Undeveloped	
Area	Gross	Net	Gross	Net
North Louisiana	95,700	47,900	7,100	3,600
East Texas	48,600	21,600	71,600	24,500
South Texas	101,200	52,700	16,300	13,100
Appalachia and other	401,200	182,400	206,600	90,400
Total	646,700	304,600	301,600	131,600

The primary term of our oil and natural gas leases expire at various dates. Most of our undeveloped acreage is held-by-production, which means that these leases are active as long as we produce oil or natural gas from the acreage or comply with certain lease terms. Upon ceasing production, these leases will expire. We have 13,200, 4,700 and 31,000 net acres with lease expirations in 2016, 2017 and 2018, respectively. The majority of this acreage with lease expirations is located in the Appalachia region. In addition, we have 10,200 net acres that are subject to continuous drilling obligations which are primarily located in the Shelby area of East Texas. Predominantly all of our expiring acreage is located within our shale resource plays. We plan to drill on the acreage subject to the continuous drilling obligation in the future to hold the acreage. We have no significant Proved Undeveloped Reserves associated with acreage expiring in 2016.

The held-by-production acreage in many cases represents potential additional drilling opportunities through down-spacing and drilling of proved undeveloped and unproved locations in the same formation(s) already producing, as well as other non-producing formations, in a given oil or natural gas field without the necessity of purchasing additional leases or producing properties.

Our significant customers

In 2015, sales to BG Energy Merchants LLC and Chesapeake Energy Marketing Inc. accounted for approximately 20% and 38%, respectively, of our total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group, plc ("BG Group") and Chesapeake Energy Marketing Inc. is a subsidiary of Chesapeake Energy Corporation ("Chesapeake"). We are managing our credit risk as a result of the current commodity price environment through the attainment of financial assurances from certain customers. The loss of any significant customer may cause a temporary interruption in sales of, or lower price for, our oil and natural gas production.

Competition

The oil and natural gas industry is highly competitive, particularly with respect to acquiring prospective oil and natural gas properties and oil and natural gas reserves. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have substantially greater financial, managerial, technological and other resources than we do. Many of these companies not only engage in the acquisition, exploration, development, and production of oil and natural gas, but also have refining operations, market refined products and their own drilling rigs and oilfield services.

The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which have delayed development drilling and other exploitation activities and have caused significant price increases and operational delays. Depending on the region, we may experience difficulties in obtaining drilling rigs and other services in certain areas as well as an increase in the cost for these services and related material and equipment. We are unable to predict when, or if, supply or demand imbalances occur or how these market-driven factors impact prices, which affects our development and exploitation programs. Competition also exists for hiring experienced personnel, particularly in petroleum engineering, geoscience, accounting and financial reporting, tax and land professions. In addition, the market for oil and natural gas producing properties is competitive. We are often outbid by competitors in our attempts to lease or acquire properties. The oil and natural gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal. Competitive conditions may be affected by future legislation and regulations as the U.S. develops new energy and climate-related policies. All of these challenges could make it more difficult to execute our growth strategy or result in an increase in our costs.

Applicable laws and regulations

General

The oil and natural gas industry is extensively regulated by numerous federal, state and local authorities. Laws and regulations affecting the oil and natural gas industry are under constant review for amendment or expansion, which could increase the regulatory burden and financial sanctions for noncompliance. Although the regulatory burden on the oil and natural gas industry increases our cost of doing business and, consequently, affects our profitability, we believe these burdens do not affect us any differently or to any greater or lesser extent than they affect others in our industry with similar types, quantities and locations of production.

The following is a summary of the more significant existing environmental, safety and other laws and regulations to which our business operations are subject and with which compliance may have a material adverse effect on our capital expenditures, earnings or competitive position.

Production regulation

Our operations are subject to a number of regulations at the federal, state and local levels. These regulations require, among other things, permits for the drilling of wells, drilling bonds and reports concerning operations. Many states, counties and municipalities in which we operate also regulate one or more of the following:

- the location of wells;
- the method of drilling, completion and operating wells;
- the surface use and restoration of properties upon which wells are drilled;
- the plugging and abandoning of wells;
- notice to surface owners and other third parties; and
- produced water and waste disposal.

State laws regulate the size and shape of drilling and spacing units or proration units governing the pooling of oil and natural gas properties. Some states, including Louisiana and Texas, allow forced pooling or integration of tracts to facilitate exploration while other states rely on voluntary pooling of lands and leases. In some instances, forced pooling or unitization may be implemented by third parties and may reduce our interest in the unitized properties. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells and generally prohibit the venting or flaring of natural gas and require that oil and natural gas be produced in a prorated, equitable system. These laws and regulations may limit the amount of oil and natural gas we can produce from our wells or limit the number of wells or the locations at which we can drill. Moreover, most states generally impose a production, ad valorem or severance tax with respect to the production and sale of oil and natural gas within its jurisdiction. Many local authorities also impose an ad valorem tax on the minerals in place. States do not generally regulate wellhead prices or engage in other, similar direct economic regulation, but there can be no assurance they will not do so in the future.

Our operations are subject to numerous stringent federal and state statutes and regulations governing the discharge of materials into the environment or otherwise relating to environmental protection, some of which carry substantial administrative, civil and criminal penalties for failure to comply. These laws and regulations may require the acquisition of a permit before drilling commences, restrict the types, quantities and concentrations of various substances that can be released into the environment in connection with drilling, production and transportation of oil and natural gas, govern the sourcing, storage and disposal of water used or produced in the drilling and completion process, restrict or prohibit drilling activities in certain areas and on certain lands lying within wetlands and other protected areas, require closing earthen impoundments and impose liabilities for pollution resulting from operations or failure to comply with regulatory filings.

Statutes, rules and regulations that apply to the exploration and production of oil and natural gas are often reviewed, amended, expanded and reinterpreted, making the prediction of future costs or the impact of regulatory compliance to new laws and statutes difficult. The regulatory burden on the oil and natural gas industry increases its cost of doing business and, consequently, adversely affects its (and our) profitability.

FERC and CFTC matters

The availability, terms and cost of downstream transportation significantly affect sales of natural gas and oil. The interstate transportation of natural gas, including regulation of the terms, conditions and rates for interstate transportation and storage of natural gas, is subject to federal regulation by the Federal Energy Regulatory Commission ("FERC") under the Natural Gas Act ("NGA"). Transportation rates under the NGA must be just and reasonable. Since 1985, FERC has implemented regulations intended to increase competition within the natural gas industry by requiring that interstate natural gas transportation be made available on an open-access, not unduly discriminatory basis. FERC's jurisdiction under the NGA excludes gathering and distribution of natural gas, so gathering and distribution of natural gas are subject to regulation by individual state laws. State regulations also govern the rates and terms for access to, and transportation of natural gas on, intrastate pipeline facilities (while intrastate pipelines may from time to time provide specific services that are subject to limited regulation by FERC). The interstate transportation of oil, including regulation of the rates, terms and conditions of service, is subject to federal regulation by FERC under the Interstate Commerce Act. Rates for such oil transportation must be just and reasonable and not unduly discriminatory. Oil transportation that is not federally regulated is left to state regulation.

The federal government recently ended its decades-old prohibition of exports of crude oil produced in the lower 48 states of the U.S. It is too recent an event to determine the impact this regulatory change may have on our operations or our sales of oil. The general perception in the industry is that ending the prohibition on exports of oil produced in the U.S. may have a positive impact on U.S. producers.

Wholesale prices for natural gas and oil are not currently regulated and are determined by the market. We cannot predict, however, whether new legislation to regulate the price of energy commodities might be proposed, what proposals, if any, might actually be enacted by Congress or the various state legislatures, and what effect, if any, the proposals might have on the operations of the underlying properties.

Under the Energy Policy Act of 2005, FERC possesses regulatory oversight over natural gas markets, including the purchase, sale and transportation activities of natural gas market participants other than intrastate pipelines. The Commodity Futures Trading Commission ("CFTC") also holds authority to monitor markets and enforce anti-market manipulation regulations with respect to the physical and financial (futures, options and swaps) energy commodities market pursuant to the Commodity Exchange Act and the Dodd Frank Wall Street Reform and Consumer Protection Act of 2010 ("Dodd Frank Act"). With regard to our physical sales of natural gas and oil, our gathering of any of these energy commodities, and any related hedging activities that we undertake, we are required to observe these anti-market manipulation laws and related regulations enforced by FERC and/or the CFTC. These agencies hold substantial enforcement authority, including the ability to assess civil penalties of up to $1 million per day per violation, to order disgorgement of profits and to recommend criminal penalties. Should we violate the anti-market manipulation laws and regulations, we could also be subject to related third party damage claims by, among others, sellers, royalty owners and taxing authorities.

Federal, state or Indian oil and natural gas leases

In the event we conduct operations on federal, state or Indian oil and natural gas leases, these operations must comply with numerous regulatory restrictions, including various nondiscrimination statutes, royalty and related valuation requirements, and certain of these operations must be conducted pursuant to certain on-site security regulations and other appropriate permits issued by the Bureau of Land Management, Bureau of Ocean Energy Management, Bureau of Safety and Environmental Enforcement or other appropriate federal, state or tribal agencies.

Surface Damage Acts

In addition, a number of states and some tribal nations have enacted surface damage statutes ("SDAs"). These laws are designed to compensate for damage caused by mineral development. Most SDAs contain entry notification and negotiation requirements to facilitate contact between operators and surface owners/users. Most also contain bonding requirements and specific expenses for exploration and surface activities. Costs and delays associated with SDAs could impair operational effectiveness and increase development costs.

Other regulatory matters relating to our pipeline and gathering system assets and rail transportation

The pipelines we use to gather and transport our oil and natural gas are subject to regulation by the U.S. Department of Transportation ("DOT") under the Hazardous Liquid Pipeline Safety Act of 1979, as amended ("HLPSA") with respect to oil, and the Natural Gas Pipeline Safety Act of 1968, as amended ("NGPSA") with respect to natural gas. The HLPSA and NGPSA govern the design, installation, testing, construction, operation, replacement and management of natural gas and hazardous liquids pipeline facilities, including pipelines transporting crude oil. Where applicable, the HLPSA and NGPSA also require us and other pipeline operators to comply with regulations issued pursuant to these acts that are designed to permit access to and allow copying of records and to make certain reports available and provide information as required by the Secretary of Transportation.

The Pipeline Safety Act of 1992, as reauthorized and amended ("Pipeline Safety Act") mandates requirements in the way that the energy industry ensures the safety and integrity of its pipelines. The law applies to natural gas and hazardous liquids pipelines, including some gathering pipelines. Central to the law are the requirements it places on each pipeline operator to prepare and implement an "integrity management program." The Pipeline Safety Act mandates a number of other requirements, including increased penalties for violations of safety standards and qualification programs for employees who perform sensitive tasks. The DOT has established a number of rules carrying out the provisions of this act. The DOT Pipeline and Hazardous Materials Safety Administration ("PHMSA") has established a new risk-based approach to determine which gathering pipelines are subject to regulation, and what safety standards regulated pipelines must meet. We could incur significant expenses as a result of these laws and regulations.

The Pipeline Safety, Regulatory Certainty, and Job Creation Act of 2011 was signed into law on January 3, 2012. This law includes a number of provisions affecting pipeline owners and operators that became effective upon approval, including increased civil penalties for violators of pipeline regulations and additional reporting requirements. Most of the changes do not impact gathering lines. The legislation requires the PHMSA to issue or revise certain regulations and to conduct various reviews, studies and evaluations. In addition, the PHMSA in August 2011 issued an Advance Notice of Proposed Rulemaking ("ANPR") regarding pipeline safety. As described in the ANPR, PHMSA is considering regulations regarding, among other things, the designation of additional high consequence areas along pipelines, minimum requirements for leak detection systems, installation of emergency flow restricting devices, and revision of valve spacing requirements. If revisions to gathering line regulations are enacted by PHMSA as a result of such ANPR, we could incur significant expenses. In October 2015, the PHMSA issued proposed new safety regulations for hazardous liquid pipelines, including a requirement that all hazardous liquid pipelines have a system for detecting leaks and that operators establish a timeline for inspections of affected pipelines following extreme weather events or natural disasters.

Any transportation of the Company's crude oil or natural gas liquids by rail is also subject to regulation by the DOT's PHMSA and the DOT's Federal Railroad Administration ("FRA") under the Hazardous Materials Regulations at 49 CFR Parts 171-180 ("HMR"), including Emergency Orders by the FRA and new regulations being proposed by the PHMSA, arising due to the consequences of train accidents and the increase in the rail transportation of flammable liquids.

In September 2013, the PHMSA issued a final rule updating its regulations to increase the maximum civil penalty from $100,000 to $200,000 for each violation for each day the violation continues, and to increase from $1,000,000 to $2,000,000 the limitation that the maximum administrative civil penalty may not exceed for any related series of violations.

U.S. federal taxation

Federal income tax laws significantly affect our operations. The principal provisions that affect us are those that permit us, subject to certain limitations, to deduct as incurred, rather than to capitalize and amortize, our share of the domestic "intangible drilling and development costs" and to claim depletion on a portion of our domestic oil and natural gas properties (up to an aggregate of 1,000 Bbls per day of domestic crude oil and/or equivalent units of domestic natural gas). Further, the federal government may adopt tax laws and/or regulations that will possibly materially adversely affect us. Some possible measures that have been proposed in the past include the repeal or elimination of percentage depletion and the immediate deduction or write-offs of intangible drilling costs. Because of the speculative nature of such measures at this time, we are unable to determine what effect, if any, future proposals would have on product demand or our results of operations.

U.S. environmental regulations

The exploration, development and production of oil and natural gas, including the operation of saltwater injection and disposal wells, are subject to various federal, state and local environmental laws and regulations. These laws and regulations can increase the costs of planning, designing, installing and operating oil and natural gas wells. Federal environmental statutes to which our domestic activities are subject include, but are not limited to:

- the Oil Pollution Act of 1990 ("OPA");
- the Clean Water Act of 1972 ("CWA");
- the Rivers and Harbors Act of 1899;
- the Comprehensive Environmental Response, Compensation and Liability Act, as amended ("CERCLA");

- the Resource Conservation and Recovery Act (“RCRA”);
- the Clean Air Act (“CAA”);
- the Safe Drinking Water Act (“SDWA”);
- the Toxic Substances Control Act of 1976 ("TSCA");
- the Endangered Species Act of 1973 (the "ESA"); and
- the Notional Environment Policy Act of 1969 (the "NEPA")

In general, the oil and natural gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. For example, the United States Environmental Protection Agency (“EPA”) has identified environmental compliance by the energy extraction section as one of its enforcement initiatives for 2014-2016 (and has solicited comments on continuing this initiative for fiscal years 2017-2019). Further, in September of 2015, the EPA issued a Compliance Alert stating that it has concerns regarding significant emissions from storage vessels, such as tanks or containers, at onshore oil and natural gas production facilities.

Our domestic activities are subject to regulations promulgated under federal statutes and comparable state statutes. We also are subject to regulations governing the handling, transportation, storage and disposal of naturally occurring radioactive materials that are found in our oil and natural gas operations. Administrative, civil and criminal penalties, as well as injunctive relief, may be imposed for non-compliance with environmental laws and regulations. Additionally, these laws and regulations may require the acquisition of permits or other governmental authorizations before we undertake certain activities, limit or prohibit other activities because of protected areas or species, restrict the types of substances used in our drilling operations, impose certain substantial liabilities for the clean-up of pollution, impose certain reporting requirements, regulate remedial plugging operations to prevent future contamination, and require substantial expenditures for compliance. We cannot predict what effect future regulation or legislation, enforcement policies, and claims for damages to property, employees, other persons and the environment resulting from our operations could have on our activities.

Under the CWA, which was amended and augmented by OPA, our release or threatened release of oil or hazardous substances into or upon waters of the United States, adjoining shorelines and wetlands and offshore areas could result in our being held responsible for: (1) the costs of removing or remediating a release; (2) administrative, civil or criminal fines or penalties; or (3) specified damages, such as loss of use, property damage and natural resource damages. The scope of our liability could be extensive depending upon the circumstances of the release. Liability can be joint and several and without regard to fault. The CWA also may impose permitting requirements for discharges of pollutants as well as certain discharges of dredged or fill material into waters of the United States, including certain wetlands, which may apply to various of our construction activities, as well as requirements to develop Spill Prevention Control and Countermeasure Plans and Facility Response Plans to address potential discharges of oil into or upon waters of the United States and adjoining shorelines. State laws governing discharges to water also may require permitting provide varying civil, criminal and administrative penalties and impose liabilities in the case of a discharge of petroleum or its derivatives, or other hazardous substances, into state waters.

CERCLA, often referred to as Superfund, and comparable state statutes, impose liability that is generally joint and several and that is retroactive for costs of investigation and remediation and for natural resource damages, without regard to fault or the legality of the original conduct, on specified classes of persons for the release of a “hazardous substance” or under state law, other specified substances, into the environment. So-called potentially responsible parties (“PRPs”) include the current and certain past owners and operators of a facility where there has been a release or threat of release of a hazardous substance and persons who disposed of or arranged for the disposal of hazardous substances found at a site. CERCLA also authorizes the EPA and, in some cases, third parties to take actions in response to threats to the public health or the environment and to seek to recover from the PRPs the cost of such action. Liability can arise from conditions on properties where operations are conducted, even under circumstances where such operations were performed by third parties not under our control, and/or from conditions at third party disposal facilities where wastes from operations were sent. Although CERCLA currently exempts petroleum (including oil and natural gas) from the definition of hazardous substance, some similar state statutes do not provide such an exemption. We cannot ensure that this exemption will be preserved in any future amendments of the act. Such amendments could have a material impact on our costs or operations. Additionally, our operations may involve the use or handling of other materials that may be classified as hazardous substances under CERCLA or regulated under similar state statutes. We may also be the owner or operator of sites on which hazardous substances have been released.

Oil and natural gas exploration and production, and possibly other activities, have been conducted at a majority of our properties by previous owners and operators. Materials from these operations remain on some of the properties and in certain instances may require remediation. In some instances, we have agreed to indemnify the sellers of producing properties from whom we have acquired reserves against certain liabilities for environmental claims associated with the properties. We do not believe the costs to be incurred by us for compliance and remediating previously or currently owned or operated properties will be material, but we cannot guarantee that result.

RCRA and comparable state and local programs impose requirements on the management, generation, treatment, storage, disposal and remediation of both hazardous and nonhazardous solid wastes. Although we believe we utilize operating and waste disposal practices that are standard in the industry, hydrocarbons or other solid wastes may have been disposed or released on or under the properties we own or lease, in addition to the locations where such wastes have been taken for disposal. In addition, many of these properties have been owned or operated by third parties. We have not had control over such parties' treatment of hydrocarbons or other solid wastes and the manner in which such substances may have been disposed or released. We also generate hazardous and non-hazardous solid waste in our routine operations. It is possible that certain wastes generated by our operations, which are currently exempt from “hazardous waste” regulations under RCRA, may in the future be designated as “hazardous waste” under RCRA or other applicable state statutes and become subject to more rigorous and costly management and disposal requirements; these wastes may not be exempt under current applicable state statutes. Non-exempt waste is subject to more rigorous and costly disposal requirements.

Our operations are subject to local, state and federal regulations for the control of emissions from sources of air pollution. The CAA and analogous state laws require certain new and modified sources of air pollutants to obtain permits prior to commencing construction. Smaller sources may qualify for exemption from permit requirements or for more streamlined permitting, for example, through qualifications for permits by rule, standard permits or general permits. Major sources of air pollutants are subject to more stringent, federally imposed requirements including additional operating permits. Federal and state laws designed to control hazardous (i.e., toxic) air pollutants may require installation of additional controls. Administrative enforcement actions for failure to comply strictly with air pollution regulations or permits are generally resolved by payment of monetary fines and correction of any identified deficiencies. Alternatively, regulatory agencies could bring lawsuits for civil penalties or require us to suspend or forgo construction, modification or operation of certain air emission sources.

On April 17, 2012, the EPA issued final rules to subject oil and natural gas operations to regulation under the New Source Performance Standards (“NSPS”), and National Emission Standards for Hazardous Air Pollutants (“NESHAPS”), programs under the CAA, and to impose new and amended requirements under both programs. The EPA rules include NSPS standards for completions of hydraulically fractured natural gas wells. Before January 1, 2015, these standards require owners/operators to reduce volatile organic compound (“VOC”) emissions from natural gas not sent to the gathering line during well completion either by flaring using a completion combustion device or by capturing the natural gas using green completions with a completion combustion device. Beginning January 1, 2015, operators must capture the natural gas and make it available for use or sale, which can be done through the use of green completions. The standards are applicable to new hydraulically fractured wells and also existing wells that are refractured. Further, the finalized regulations also establish specific new requirements, which became effective in 2012, for emissions from compressors, controllers, dehydrators, storage tanks, natural gas processing plants and certain other equipment. These rules may require changes to our operations, including the installation of new equipment to control emissions. We continuously evaluate the effect these rules and amendments will have on our business.

In September of 2015 the EPA proposed rules that would establish new air emission controls for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The EPA’s proposed rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, fugitive emissions from well sites and compressors, equipment leaks at natural gas processing plants, and pneumatic pumps.

In addition, the rule would extend current volatile organic compound requirements established in 2012 to remaining unregulated equipment within the source category, such as hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations, and pneumatic pumps. Another key component of the proposal is that it contemplates periodically monitoring methane emissions using imaging optical gas imaging instead of traditional observation methods.

Concurrent with this proposal, the EPA published another proposal to clarify the term “adjacent” in the definitions of: “building, structure, facility or installation” used to determine the “stationary source” for purposes of the Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) programs and “major source” in the title V program as applied to the oil and natural gas sector. The grouping together of sources may cause a group of sources to be treated as a “major source” and face enhanced regulation under federal environmental laws, including the CAA.

More stringent laws and regulations protecting the environment may be adopted in the future and we may be required to incur material expenses to comply with them. For example, although federal legislation regarding the control of emissions of greenhouse gases (“GHGs”) for the present, appears unlikely, the EPA has been implementing regulatory measures under existing CAA authority and some of those regulations may affect our operations. GHGs are certain gases, including carbon dioxide, a product of the combustion of natural gas, and methane, a primary component of natural gas, that may be contributing to warming of the Earth's atmosphere resulting in climatic changes. These GHG regulations could require us to incur increased operating costs and could have an adverse effect on demand for the oil and natural gas we produce.

There are various federal and state programs that regulate the conservation and development of coastal resources. The federal Coastal Zone Management Act ("CZMA") was passed in 1972 to preserve and, where possible, restore the natural resources of the coastal zone of the United States. The CZMA provides for federal grants for state management programs that regulate land use, water use and coastal development. Many states, including Texas, also have coastal management programs, which provide for, among other things, the coordination among local and state authorities to protect coastal resources through regulating land use, water, and coastal development. Coastal management programs also may provide for the review of state and federal agency rules and agency actions for consistency with the goals and policies of the state coastal management plan. In the event our activities trigger these programs, this review of agency rules and actions may impact other agency permitting and review activities, resulting in possible delays or restrictions of our activities and adding an additional layer of review to certain activities undertaken by us.

ESA was established to protect endangered and threatened species. Pursuant to that act, if a species is listed as threatened or endangered, restrictions may be imposed on activities adversely affecting that species' habitat. Similar protections are offered to migratory birds under the Migratory Bird Treaty Act. The U.S. Fish and Wildlife Service must also designate the species' critical habitat and suitable habitat as part of the effort to ensure survival of the species. A critical habitat or suitable habitat designation could result in further material restrictions to land use and may materially delay or prohibit land access for oil and natural gas development. If we were to have a portion of our leases designated as critical or suitable habitat, it may adversely impact the value of the affected leases.

Oil and natural gas exploration and production activities on federal lands may be subject to the NEPA, which requires federal agencies, including the Department of the Interior (the "DOI"), 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. To the extent that our exploration and development plans include leases on federal lands, the NEPA requirements have the potential to delay or impose additional conditions upon the development of oil and natural gas projects.

Hydraulic fracturing activities

Over the past few years, there has been an increased focus on environmental aspects of hydraulic fracturing activities in the United States. While hydraulic fracturing is typically regulated by state oil and natural gas commissions in the United States, there have recently been a number of regulatory initiatives at the federal and local levels as well as by other state agencies.

Nearly all of our exploration and production operations depend on the use of hydraulic fracturing to enhance production from oil and natural gas wells. Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into formations to fracture the surrounding rock and stimulate production. Our hydraulic fracturing activities are focused in our shale plays in South Texas, East Texas, North Louisiana and Appalachia. Predominantly all of our undeveloped properties would not be economical without the use of hydraulic fracturing to stimulate production from the well.

The SDWA currently exempts from regulation the injection of fluids or propping agents (other than diesel fuels) for hydraulic fracturing operations. Congress has periodically considered legislation to amend the federal SDWA to remove the exemption from regulation and permitting that is applicable to hydraulic fracturing operations and to require reporting and disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Sponsors of bills previously introduced before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Many states have considered or adopted legislation regulating hydraulic fracturing, including the disclosure of chemicals used in the process. These bills, or similar legislation, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance.

In addition, the EPA has recently been taking action to assert federal regulatory authority over hydraulic fracturing using diesel under the SDWA's Underground Injection Control Program and has issued guidance regarding its authority over the permitting of these activities. At the same time, the White House Council on Environmental Quality is coordinating an administration-wide review of hydraulic fracturing practices and the EPA has commenced a study of the potential impacts of hydraulic fracturing activities on drinking water resources. As part of these studies, the EPA has requested that certain companies provide them with information concerning the chemicals used in the hydraulic fracturing process. These studies, depending on their results, could spur additional initiatives to regulate hydraulic fracturing under the SDWA or otherwise.

The EPA also proposed new effluent limitations for the treatment of and discharge of wastewater resulting from hydraulic fracturing activity. If enacted, theses limits may increase our disposal costs and our business operations.

Additionally, the Bureau of Land Management has proposed regulations on hydraulic fracturing activities on Federal land. The EPA has also announced an initiative under the TSCA to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals, and is working on regulations governing wastewater generated by hydraulic fracturing. In addition, state, local and river basin conservancy districts have all previously exercised their various regulatory powers to curtail and, in some cases, place moratoriums on hydraulic fracturing. Regulations include express inclusion of hydraulic fracturing into existing regulations covering other aspects of exploration and production and specifically may include, but not be limited to, the following:

- requirement that logs and pressure test results are included in disclosures to state authorities;
- disclosure of hydraulic fracturing fluids, chemicals, proppants and the ratios of same used in operations;
- specific disposal regimens for hydraulic fracturing fluid;
- replacement/remediation of contaminated water assets; and
- minimum depth of hydraulic fracturing.

Local regulations, which may be preempted by state and federal regulations, have included the following which may extend to all operations including those beyond hydraulic fracturing:

- noise control ordinances;
- traffic control ordinances;
- limitations on the hours of operations; and
- mandatory reporting of accidents, spills and pressure test failures.

If in the course of our routine oil and natural gas operations, surface spills and leaks occur, including casing leaks of oil or other materials, we may incur penalties and costs for waste handling, remediation and third party actions for damages. Moreover, we are only able to directly control the operations of the wells that we operate. Notwithstanding our lack of control over wells owned by us but operated by others, the failure of the operator to comply with applicable environmental regulations may be attributable to us and may impose legal liabilities upon us.

If substantial liabilities to third parties or governmental entities are incurred, the payment of such claims may reduce or eliminate the funds available for project investment or result in loss of our properties. Although we maintain insurance coverage we consider to be customary in the industry, we are not fully insured against all of these risks, either because insurance is not available or because of high premiums. Accordingly, we may be subject to liability or may lose substantial portions of properties due to hazards that cannot be insured against or have not been insured against due to prohibitive premiums or for other reasons. The imposition of any of these liabilities or compliance obligations on us may have a material adverse effect on our financial condition and results of operations.

We do not anticipate that we will be required in the near future to expend amounts that are material in relation to our total capital expenditures program complying with current environmental laws and regulations. As these laws and regulations are frequently changed and are subject to interpretation, our assessment regarding the cost of compliance or the extent of liability risks may change in the future.

OSHA and other regulations

To the extent not preempted by other applicable laws, we are subject to the requirements of the federal OSHA and comparable state statutes, where applicable. The OSHA hazard communication standard, the EPA community right-to-know regulations under the Title III of CERCLA and similar state statutes, where applicable, require that we maintain and/or disclose information about hazardous materials used or produced in our operations. We believe that we are in substantial compliance with these applicable requirements and with other OSHA and comparable state requirements.

Title to our properties

When we acquire developed properties we conduct a title investigation, which will most often include either reviewing or obtaining a title opinion. However, when we acquire undeveloped properties, as is common industry practice, we usually conduct little or no investigation of title other than a preliminary review of local real property and/or mineral records. We will conduct title investigations and, in most cases, obtain a title opinion of local counsel for the drill site before we begin drilling operations. We believe that the methods we utilize for investigating title prior to acquiring any property are consistent with practices customary in the oil and natural gas industry and that our practices are adequately designed to enable us to acquire marketable title to properties. However, some title risks cannot be avoided, despite the use of customary industry practices.

Our properties are generally burdened by:

- customary royalty and overriding royalty interests;
- liens incident to operating agreements; and
- liens for current taxes and other burdens and minor encumbrances, easements and restrictions.

We believe that none of these burdens materially detract from the value of our properties or materially interfere with property used in the operation of our business. In addition to the foregoing listed burdens, substantially all of our properties are pledged as collateral under the EXCO Resources Credit Agreement and the Second Lien Term Loans.

Operational factors and insurance

Oil and natural gas exploration and development involves a high degree of risk. In the event of explosions, environmental damage, or other accidents such as well fires, blowouts, equipment failure and human error, substantial liabilities to third parties or governmental entities may be incurred, the satisfaction of which could substantially reduce available cash and possibly result in the loss of oil and natural gas properties. As is common in the oil and natural gas industry, we are not fully insured against all risks associated with our business either because such insurance is not available or because we believe the premium costs are prohibitive. A loss not fully covered by insurance could have a materially adverse effect on our operating results, financial position or cash flows. For further discussion on risks see “Item 1A. Risk Factors - We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flows.”

We currently carry automobile liability, general liability and excess liability insurance with a combined annual limit of $101 million per occurrence and in the aggregate. These insurance policies contain maximum policy limits and deductibles ranging from $1,000 to $25,000 that must be met prior to recovery, and are subject to customary exclusions and limitations. Our automobile and general liability insurance covers us and our subsidiaries for third-party claims and liabilities arising out of lease operations and related activities. The excess liability insurance is in addition to, and is triggered if; the automobile and general liability insurance per occurrence limit is reached. Further, we currently carry $45 million of pollution coverage, $25 million of well control (blowout) coverage and $79 million of wellhead, surface equipment and tank coverage with deductibles ranging from $100,000 to $500,000.

We require our third-party contractors to sign master service agreements in which they generally agree to indemnify us for the injury and death of the service provider's employees as well as contractors and subcontractors that are hired by the service provider. Similarly, we agree to indemnify our third-party contractors against claims made by our employees and our other contractors. Additionally, each party generally is responsible for damage to its own property.

Our third-party contractors that perform hydraulic fracturing operations for us sign master service agreements containing the indemnification provisions noted above. We do not currently have any insurance policies in effect that are intended to provide coverage for losses solely related to hydraulic fracturing operations. We believe that our general liability, excess liability and pollution insurance policies would cover third-party claims related to hydraulic fracturing operations and associated legal expenses, in accordance with, and subject to, the terms of such policies. However, these policies generally will not cover fines and penalties. Further, these policies may not cover the costs and expenses related to government-mandated environmental clean-up responsibilities, or may do so on a limited basis.

Our employees

As of December 31, 2015, we employed 315 persons. None of our employees are represented by unions or covered by collective bargaining agreements. To date, we have not experienced any strikes or work stoppages due to labor problems, and we consider our relations with our employees to be satisfactory. We also utilize the services of independent consultants and contractors.

Forward-looking statements

This Annual Report on Form 10-K contains forward-looking statements, as defined in Section 27A of the Securities Act of 1933, as amended ("Securities Act") and Section 21E of the Securities Exchange Act of 1934, as amended ("the Exchange Act"). These forward-looking statements relate to, among other things, the following:

- our future financial and operating performance and results;
- our business strategy;
- market prices;
- our future use of derivative financial instruments; and
- our plans and forecasts.

We have based these forward-looking statements on our current assumptions, expectations and projections about future events. We use the words “may,” “expect,” “anticipate,” “estimate,” “believe,” “continue,” “intend,” “plan,” “potential,” “project,” “budget” and other similar words to identify forward-looking statements. The statements that contain these words should be read carefully because they discuss future expectations, contain projections of results of operations or our financial condition and/or state other “forward-looking” information. We do not undertake any obligation to update or revise any forward-looking statements, except as required by applicable securities laws. These statements also involve risks and uncertainties that could cause our actual results or financial condition to materially differ from our expectations in this prospectus and the documents incorporated herein by reference, including, but not limited to:

- fluctuations in the prices of oil and natural gas;
- the availability of oil and natural gas;
- future capital requirements and availability of financing, including limitations on our ability to incur certain types of indebtedness under our debt agreements;
- our ability to meet our current and future debt service obligations, including our ability to maintain compliance with our debt covenants;
- disruption of credit and capital markets and the ability of financial institutions to honor their commitments;
- estimates of reserves and economic assumptions, including estimates related to acquisitions and dispositions of oil and natural gas properties;
- geological concentration of our reserves;
- risks associated with drilling and operating wells;
- exploratory risks, including those related to our activities in shale formations;
- discovery, acquisition, development and replacement of oil and natural gas reserves;
- cash flow and liquidity;
- timing and amount of future production of oil and natural gas;
- availability of drilling and production equipment;
- availability of water and other materials for drilling and completion activities;
- marketing of oil and natural gas;
- political and economic conditions and events in oil-producing and natural gas-producing countries;
- title to our properties;
- litigation;
- competition;
- our ability to attract and retain key personnel;
- general economic conditions, including costs associated with drilling and operations of our properties;
- our ability to comply with the listing requirements of, and maintain the listing of our common shares on, the New York Stock Exchange ("NYSE");
- environmental or other governmental regulations, including legislation to reduce emissions of greenhouse gases, legislation of derivative financial instruments, regulation of hydraulic fracture stimulation and elimination of income tax incentives available to our industry;
- receipt and collectability of amounts owed to us by purchasers of our production and counterparties to our derivative financial instruments;
- decisions whether or not to enter into derivative financial instruments;
- potential acts of terrorism;
- our ability to manage joint ventures with third parties, including the resolution of any material disagreements and our partners’ ability to satisfy obligations under these arrangements;

- actions of third party co-owners of interests in properties in which we also own an interest;
- fluctuations in interest rates;
- our ability to effectively integrate companies and properties that we acquire; and
- our ability to execute our business strategies and other corporate actions.

We believe that it is important to communicate our expectations of future performance to our investors. However, events may occur in the future that we are unable to accurately predict, or over which we have no control. We caution users of the financial statements not to place undue reliance on any forward-looking statements. When considering our forward-looking statements, keep in mind the risk factors and other cautionary statements in this Annual Report on Form 10-K. The risk factors noted in this Annual Report on Form 10-K provide examples of risks, uncertainties and events that may cause our actual results to differ materially from those contained in any forward-looking statement. Please see “Risk Factors” for a discussion of certain risks related to our business, indebtedness and common shares.

Our revenues, operating results and financial condition depend substantially on prevailing prices for oil and natural gas and the availability of capital from the EXCO Resources Credit Agreement and other sources. Declines in oil or natural gas prices may have a material adverse effect on our financial condition, liquidity, results of operations, the amount of oil or natural gas that we can produce economically and the ability to fund our operations. Historically, oil and natural gas prices and markets have been volatile, with prices fluctuating widely, and they are likely to continue to be volatile.

Glossary of selected oil and natural gas terms

The following are abbreviations and definitions of terms commonly used in the oil and natural gas industry and this Annual Report on Form 10-K.

2-D seismic. Geophysical data that depicts the subsurface strata in two dimensions.

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

Appraisal wells. Wells drilled to convert an area or sub-region from the resource to the reserves category.

Analogous reservoir. Analogous reservoirs, as used in resources assessments, have similar rock and fluid properties, reservoir conditions (depth, temperature, and pressure) and drive mechanisms, but are typically at a more advanced stage of development than the reservoir of interest and thus may provide concepts to assist in the interpretation of more limited data and estimation of recovery. When used to support proved reserves, an “analogous reservoir” refers to a reservoir that shares the following characteristics with the reservoir of interest: (i) same geological formation (but not necessarily in pressure communication with the reservoir of interest); (ii) same environment of deposition; (iii) similar geological structure; and (iv) same drive mechanism.

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

Bcf. One billion cubic feet of natural gas.

Bcfe. One billion cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas. This ratio of Bbl to Mcf is commonly used in the oil and natural gas industry and represents the approximate energy equivalent of natural gas to oil or NGLs, and does not represent the sales price equivalency of natural gas to oil or NGLs. Currently the sales price of a Bbl or NGL is significantly higher than the sales price of six Mcf of natural gas.

Boepd. Barrels of oil equivalent per day.

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

Completion. The installation of permanent equipment for the production of oil or natural gas, or, in the case of a dry hole, the reporting to the appropriate authority that the well has been abandoned.

Deterministic method. The method of estimating reserves or resources when a single value for each parameter (from the geoscience, engineering, or economic data) in the reserves calculation is used in the reserves estimation procedure.

Developed acreage. The number of acres which are allocated or assignable to producing wells or wells capable of production.

Development well. A well 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; Dry well. A well found to be incapable of producing either oil or natural gas in sufficient quantities to justify completion as an oil or natural gas well.

Economically producible. As it relates to a resource, a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation.

Estimated ultimate recovery (EUR). Estimated ultimate recovery is the sum of reserves remaining as of a given date and cumulative production as of that date.

Exploitation. The continuing development of a known producing formation in a previously discovered field. To maximize the ultimate recovery of oil or natural gas from the field by development wells, secondary recovery equipment or other suitable processes and technology.

Exploratory well. An exploratory well is a well drilled to find a new field or to find a new reservoir in a field previously found to be productive of oil or natural gas in another reservoir. Generally, an exploratory well is any well that is not a development well, a service well, or a stratigraphic test well.

Farmout. An assignment of an interest in a drilling location and related acreage conditional upon the drilling of a well on that location.

Formation. A succession of sedimentary beds that were deposited under the same general geologic conditions.

Fracture stimulation. A stimulation treatment routinely performed involving the injection of water, sand and chemicals under pressure to stimulate hydrocarbon production.

Full cost pool. The full cost pool consists of all costs associated with property acquisition, exploration, and development activities for a company using the full cost method of accounting. Additionally, any internal costs that can be directly identified with acquisition, exploration and development activities are included. Any costs related to production, general corporate overhead or similar activities are not included.

Gross acres or gross wells. The total acres or wells, as the case may be, in which a working interest is owned.

Held-by-production. A provision in an oil, natural gas and mineral lease that perpetuates a company's right to operate a property or concession as long as the property or concession produces a minimum paying quantity of oil or natural gas.

Horizontal wells. Wells which are drilled at angles greater than 70 degrees from vertical.

Initial production rate. Generally, the maximum 24 hour production volume from a well.

Mbbl. One thousand stock tank barrels.

Mcf. One thousand cubic feet of natural gas.

Mcfe. One thousand cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Mmbbl. One million stock tank barrels.

Mmbtu. One million British thermal units.

Mmcf. One million cubic feet of natural gas.

Mmcf/d. One million cubic feet of natural gas per day.

Mmcfe. One million cubic feet of natural gas equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas. This ratio of Bbl to Mcf is commonly used in the oil and natural gas industry and represents the approximate energy equivalent of natural gas to oil or NGLs, and does not represent the sales price equivalency of natural gas to oil or NGLs. Currently the sales price of a Bbl or NGL is significantly higher than the sales price of six Mcf of natural gas.

Mmcfe/d. One million cubic feet of natural gas equivalent per day calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas.

Mmmbtu. One billion British thermal units.

Net acres or net wells. Exists when the sum of fractional ownership interests owned in gross acres or gross wells equals one. We compute the number of net wells by totaling the percentage interest we hold in all our gross wells.

NYMEX. New York Mercantile Exchange.

NGLs. The combination of ethane, propane, butane and natural gasolines that when removed from natural gas become liquid under various levels of higher pressure and lower temperature.

Overriding royalty interest. An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of the costs of production.

Pad drilling. The drilling of multiple wells from the same site.

Play. A term applied to a portion of the exploration and production cycle following the identification by geologists and geophysicists of areas with potential oil and natural gas reserves.

Present value of estimated future net revenues or PV-10. The present value of estimated future net revenues is an estimate of future net revenues from a property at the date indicated, without giving effect to derivative financial instrument activities, after deducting production and ad valorem taxes, future capital costs, abandonment costs and operating expenses, but before deducting future income taxes. The future net revenues have been discounted at an annual rate of 10% to determine their "present value." The present value is shown to indicate the effect of time on the value of the net revenue stream and should not be construed as being the fair market value of the properties. Estimates have been made using constant oil and natural gas prices and operating and capital costs at the date indicated, at its acquisition date, or as otherwise indicated.

Probabilistic method. The method of estimation of reserves or resources when the full range of values that could reasonably occur for each unknown parameter (from the geoscience and engineering data) is used to generate a full range of possible outcomes and their associated probabilities of occurrence.

Productive well. A productive well is a well that is not a dry well.

Proved Developed Reserves. These 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 reserves estimate if the extraction is by means not involving a well.

Proved Reserves. Proved oil and natural gas 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.

The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) 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 gas on the basis of available geoscience and engineering data.

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. Where direct observation from well penetrations has defined a highest known oil (HKO) elevation and the potential exists for an associated 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.

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

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. 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.

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. 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.

Under no circumstances shall estimates for undeveloped reserves be attributable to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir or by other evidence using reliable technology establishing Reasonable Certainty.

Recompletion. An operation within an existing well bore to make the well produce oil and/or natural gas from a different, separately producible zone other than the zone from which the well had been producing.

Reasonable Certainty. If deterministic methods are used, Reasonable Certainty means a high degree of confidence that the quantities will be recovered. If probabilistic methods are used, there should be at least a 90% probability that the quantities actually recovered will equal or exceed the estimate. A high degree of confidence exists if the quantity is much more likely to be achieved than not, and, as changes due to increased availability of geoscience (geological, geophysical, and geochemical), engineering, and economic data are made to EUR with time, reasonably certain EUR is much more likely to increase or remain constant than to decrease.

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

Resources. Resources are quantities of oil and natural gas estimated to exist in naturally occurring accumulations. A portion of the resources may be estimated to be recoverable, and another portion may be considered to be unrecoverable. Resources include both discovered and undiscovered accumulations.

Royalty interest. An interest in an oil and/or natural gas property entitling the owner to a share of oil and natural gas production free of the costs of production.

Shale. Fine-grained sedimentary rock composed mostly of consolidated clay or mud. Shale is the most frequently occurring sedimentary rock.

Shut-in well. A producing well that has been closed down temporarily for, among other things, economics, cleaning out, building up pressure, lack of a market or lack of equipment.

Spud. To start the well drilling process.

Standardized Measure of discounted future net cash flows or the Standardized Measure. Under the Standardized Measure, future cash flows are estimated by applying the simple average spot prices for the trailing 12 month period using the first day of each month beginning on January 1 and ending on December 1 of each respective year, adjusted for price differentials, to the estimated future production of year-end Proved Reserves. Future cash inflows are reduced by estimated future production and development costs based on period-end and future plugging and abandonment costs to determine pre-tax cash inflows. Future income taxes are computed by applying the statutory tax rate to the excess of pre-tax cash inflows over our tax basis in the associated properties. Future net cash inflows after income taxes are discounted using a 10% annual discount rate to arrive at the Standardized Measure.

Stock tank barrel. 42 U.S. gallons liquid volume.

Tcf. One trillion cubic feet of natural gas.

Tcfe. One trillion cubic feet equivalent calculated by converting one Bbl of oil or NGLs to six Mcf of natural gas. This ratio of Bbl to Mcf is commonly used in the oil and natural gas industry and represents the approximate energy equivalent of natural gas to oil or NGLs, and does not represent the sales price equivalency of natural gas to oil or NGLs. Currently the sales price of a Bbl or NGL is significantly higher than the sales price for six Mcf of natural gas.

Undeveloped acreage. Leased acreage on which wells have not been drilled or completed to a point that would permit the production of economic quantities of oil and natural gas regardless of whether such acreage contains Proved Reserves.

Working interest. The operating interest that gives the owner the right to drill, produce and conduct activities on the property and a share of production.

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

Available information

We make available, free of charge, our Annual Report on Form 10-K, Quarterly Reports on Form 10-Q, Current Reports on Form 8-K and amendments to these reports on our website at *www.excoresources.com* as soon as reasonably practicable after those reports and other information is electronically filed with, or furnished to, the SEC.

Item 1A. Risk Factors

The risk factors noted in this section and other factors noted throughout this Annual Report on Form 10-K, including those risks identified in "Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations" describe examples of risks, uncertainties and events that may cause our actual results to differ materially from those contained in any forward-looking statement.

If one or more of these risks or uncertainties materialize, or if underlying assumptions prove incorrect, actual outcomes may vary materially from those included in this Annual Report on Form 10-K.

Risks Relating to Our Business

Oil and natural gas prices, which are subject to fluctuations, have declined substantially from historical highs and may remain depressed for the foreseeable future. The depression in oil and natural gas prices has, and is expected to continue to, adversely affect our revenues as well as our ability to maintain or increase our borrowing capacity, repay current or future indebtedness and obtain additional capital on attractive terms.

Our future financial condition, access to capital, cash flow and results of operations depend upon the prices we receive for our oil and natural gas. We are particularly dependent on prices for natural gas. As of December 31, 2015, approximately 86% of our Proved Reserves, 89% of our production and 69% of our total revenues were natural gas. Historically, oil and natural gas prices have been volatile and are subject to fluctuations in response to changes in supply and demand, market uncertainty and a variety of additional factors that are beyond our control.

In the past, prices of oil and natural gas have been extremely volatile, and we expect this volatility to continue. During 2015, the NYMEX price for natural gas fluctuated from a high of $3.23 per Mmbtu to a low of $1.76 per Mmbtu, while the NYMEX West Texas Intermediate crude oil price ranged from a high of $61.43 per Bbl to a low of $34.73 per Bbl. For the five years ended December 31, 2015, the NYMEX Henry Hub natural gas price ranged from a high of $6.15 per Mmbtu to a low of $1.76 per Mmbtu, while the NYMEX West Texas Intermediate ("WTI") crude oil price ranged from a high of $113.93 per Bbl to a low of $34.73 per Bbl.

During 2015, oil and natural gas prices experienced a significant decline and the depression of oil and natural gas prices may continue for the foreseeable future. On December 31, 2015, the spot market price for natural gas at Henry Hub was $2.34 per Mmbtu, a 19% decrease from December 31, 2014. On December 31, 2015, the spot market price for crude oil at Cushing was $37.04 per Bbl, a 30% decrease from December 31, 2014. For 2015, our average realized prices (before the impact of derivative financial instruments) for oil and natural gas were $43.89 per Bbl and $2.05 per Mcf, respectively, compared with 2014 average realized prices of $87.80 per Bbl and $3.79 per Mcf, respectively.

Our revenues, cash flow and profitability and our ability to maintain or increase our borrowing capacity, to repay current or future indebtedness and to obtain additional capital on attractive terms depend substantially upon oil and natural gas prices. The lower average prices realized for oil and natural gas in 2015, coupled with the slow recovery in financial markets that has significantly limited and increased the cost of capital, have compelled most oil and natural gas producers, including us, to reduce levels of exploration, drilling and production activity. This has had a significant effect on our capital resources, liquidity and operating results. Any sustained reductions in oil and natural gas prices will directly affect our revenues and can indirectly impact expected production by changing the amount of funds available to us to reinvest in exploration and development activities. Further reductions in oil and natural gas prices could also reduce the quantities of reserves that are commercially recoverable. A reduction in our reserves could have other adverse consequences, including a possible downward redetermination of the availability of borrowings under the EXCO Resources Credit Agreement, which would further restrict our liquidity. Additionally, further or continued declines in prices could result in additional non-cash charges to earnings due to impairments to our oil and natural gas properties. Any such impairments could have a material adverse effect on our results of operations in the period taken.

Changes in the differential between NYMEX or other benchmark prices of oil and natural gas and the reference or regional index price used to price our actual oil and natural gas sales could have a material adverse effect on our results of operations and financial condition.

The reference or regional index prices that we use to price our oil and natural gas sales sometimes reflect a discount to the relevant benchmark prices, such as NYMEX. The difference between the benchmark price and the price we reference in our sales contracts is called a differential. We cannot accurately predict oil and natural gas differentials. Changes in differentials between the benchmark price for oil and natural gas and the reference or regional index price we reference in our sales contracts could have a material adverse effect on our results of operations and financial condition. We have experienced significant volatility in our price differentials including crude oil production from the Eagle Ford shale and natural gas production from certain areas in Appalachia. Our crude oil production from the Eagle Ford shale is currently sold at a price based on the Phillips 66 West Texas Intermediate index plus or minus the differential to the Argus Louisiana Light Sweet index. During 2015, the monthly average of this differential ranged from a high of Phillips 66 West Texas Intermediate plus $6.68 per barrel to a low of Phillips 66 West Texas Intermediate plus $1.40 per barrel. Our natural gas production from the Marcellus shale in Northeast Pennsylvania is sold at a price based on a Platts index that represents value into the Transco Leidy Pipeline. Due to the increased production in this region without an offsetting increase in pipeline capacity or infrastructure to the Northeast United States markets, this differential in 2015 ranged from a low of NYMEX less $0.87 per Mmbtu to a high of NYMEX less $1.85 per Mmbtu. These differentials vary depending on factors such as supply, demand, pipeline capacity, infrastructure, and weather.

Continuing impairments of our asset values could have a substantial negative effect on our results of operations and net worth.

We follow the full cost method of accounting for our oil and natural gas properties. Depending upon oil and natural gas prices in the future, and at the end of each quarterly and annual period when we are required to test the carrying value of our assets using full cost accounting rules, we may be required to record an impairment to the value of our oil and natural gas properties if the present value of the after-tax future cash flows from our oil and natural gas properties falls below the net book value of these properties. We have in the past experienced, and may experience in the future, ceiling test impairments with respect to our oil and natural gas properties.

Our evaluation of impairment is based upon estimates of Proved Reserves. The value of our Proved Reserves may be lowered in future periods as a result of a decline in prices of oil and natural gas, a downward revision of our oil and natural gas reserves or other factors. As a result, our evaluation of impairment for future periods is subject to uncertainties inherent in estimating quantities of Proved Reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Because several of these factors are beyond our control, we cannot accurately predict or control the amount of ceiling test impairments in future periods. Future ceiling test impairments could negatively affect our results of operations and net worth.

For the year ended December 31, 2015, we recognized impairments of $1.2 billion to our proved oil and natural gas properties. For the year ended December 31, 2014, we did not recognize any impairments to our proved oil and natural gas properties and for the year ended December 31, 2013, we recognized impairments of $108.5 million to our proved oil and natural gas properties. We may have additional impairments of our oil and natural gas properties in future periods if the cost of our unamortized proved oil and natural gas properties exceeds the limitation under the full cost method of accounting. As a result of the decline in oil and natural gas prices during 2015, we expect to recognize additional impairments to our oil and natural gas properties in 2016 if prices do not increase. We also may recognize impairments if some of our undeveloped locations are determined to no longer be economically viable as a result of low prices. In addition to the negative effect this has on our balance sheet and retained earnings and the reduction in our assets, future reductions in the value of our properties could cause a downward redetermination of our borrowing capacity under the EXCO Resources Credit Agreement.

We also test goodwill for impairment annually or when circumstances indicate that an impairment may exist. If the book value of our reporting unit exceeds the estimated fair value of the reporting unit, an impairment charge will occur, which would negatively impact our results of operations and net worth. As a result of our testing of goodwill for impairment, we did not record an impairment charge for the periods ended December 31, 2015, 2014 and 2013.

Our short-term liquidity is constrained and could severely impact our cash flow and our development of properties.

Currently, our principal sources of liquidity are cash flows from operations and borrowings under the EXCO Resources Credit Agreement. Our borrowing base under the EXCO Resources Credit Agreement is currently $375.0 million and is scheduled for redetermination in March 2016. While we believe our existing capital resources are sufficient to conduct our operations through 2016, any reduction in our borrowing base could result in our liquidity being limited to our cash flow from operations, which is currently in decline as a result of the depressed commodity price environment. If our borrowing base is materially reduced or we are no longer able to draw on the EXCO Resources Credit Agreement or generate sufficient cash flow from operations, we may not be able to fund our operations and drilling activities or pay the interest on our debt, which would result in us defaulting under our various debt instruments and may force us to seek bankruptcy protection or pursue other restructuring alternatives.

The depressed commodity price environment coupled with our substantial indebtedness and liquidity issues may impact our business and operations.

In light of the depressed commodity price environment, there is risk that, among other things:

- third parties' confidence in our commercial or financial ability to explore and produce oil and natural gas could erode, which could impact our ability to execute on our business strategy;
- it may become more difficult to retain, attract or replace key employees;
- employees could be distracted from performance of their duties or more easily attracted to other career opportunities; and
- our suppliers, hedge counterparties, vendors and service providers could renegotiate the terms of our arrangements, terminate their relationship with us or require financial assurances from us.

The occurrence of certain of these events may have a material adverse effect on our business, results of operations and financial condition.

In the future, we may seek bankruptcy protection, which may harm our business and place our equity holders at significant risk of losing all of their interests in our business.

We are analyzing various strategic alternatives to address our liquidity and capital structure, including strategic and refinancing alternatives. However, if oil and natural gas prices do not improve in the future, a filing under Chapter 11 of the Bankruptcy Code may be unavoidable. Seeking bankruptcy protection could have a material adverse effect on our business, financial condition, results of operations and liquidity. So long as a proceeding related to a Chapter 11 bankruptcy proceeding is ongoing, our senior management would be required to spend a significant amount of time and effort dealing with the reorganization instead of focusing exclusively on our business operations. Bankruptcy protection also might make it more difficult to retain management and other key personnel necessary to the success and growth of our business. In addition, the longer a proceeding related to a bankruptcy continues, the more likely it is that our customers and suppliers would lose confidence in our ability to reorganize our businesses successfully and would seek to establish alternative commercial relationships or request financial assurances such as letters of credit and cash deposits.

Additionally, we have a significant amount of indebtedness that is senior to our existing common shares in our capital structure. As a result, we believe that seeking bankruptcy protection could cause our common shares to be canceled, resulting in a limited recovery for shareholders, if any, and place equity holders at significant risk of losing all of their interests in our business.

We may encounter obstacles to marketing our oil and natural gas, which could adversely impact our revenues.

Our ability to market our oil and natural gas production will depend upon the availability and capacity of gathering systems, pipelines and other transportation facilities. We are primarily dependent upon third parties to transport our production. Transportation space on the gathering systems and pipelines we utilize is occasionally limited or unavailable due to repairs, outages caused by accidents or other events, or improvements to facilities or due to space being utilized by other companies that have priority transportation agreements. We have experienced production curtailments in our producing regions resulting from capacity restraints, offsetting fracturing stimulation operations and short term shutdowns of certain pipelines for maintenance purposes. As we have increased our knowledge of our shale properties, we have begun to shut in production on adjacent wells when conducting completion operations. Due to the high production capabilities of these wells, these volumes can be significant. Our access to transportation options can also be affected by U.S. federal and state regulation of oil and natural gas production and transportation, general economic conditions and changes in supply and demand. These factors and the availability of markets are beyond our control. If market factors dramatically change, the impact on our revenues could be substantial and could adversely affect our ability to produce and market oil and natural gas and the value of our common shares.

We have entered into marketing agreements with third-parties to sell a significant percentage of our anticipated oil and natural gas production in the East Texas, North Louisiana and South Texas regions. If these third-parties are unable or otherwise fail to market the oil and natural gas we produce, we would be required to find alternate means to market our production, which could increase our costs, reduce the revenues we might obtain from the sale of our oil and natural gas production or have a material adverse effect on our business, results of operations or financial condition.

We may experience a financial loss if any of our significant customers fail to pay us for our oil or natural gas or reduce the volume of oil and natural gas that they purchase from us.

Our ability to collect payments from the sale of oil and natural gas to our customers depends on the payment ability of our customer base, which includes several significant customers. If any one or more of our significant customers fails to pay us for any reason, we could experience a material loss. We are managing our credit risk as a result of the current commodity price environment through the attainment of financial assurances from certain customers. In addition, if any of our significant customers cease to purchase our oil or natural gas or reduce the volume of the oil or natural gas that they purchase from us, the loss or reduction could have a detrimental effect on our production volumes and may cause a temporary interruption in sales of, or a lower price for, our oil and natural gas.

Market conditions or operational impediments, such as lack of available transportation or infrastructure, may hinder our production or adversely impact our ability to receive market prices for our production or to achieve expected drilling results.

Market conditions or the unavailability of satisfactory oil and natural gas transportation arrangements or infrastructure may hinder our access to oil and natural gas markets or delay our production. The availability of a ready market for our oil and natural gas production depends on a number of factors, including the demand for and supply of oil and natural gas and the proximity of reserves to pipelines and terminal facilities. Our ability to market our production depends, in substantial part, on the availability and capacity of gathering systems, pipelines, processing facilities and oil and condensate trucking operations owned and operated by third-parties. Our failure to obtain these services on acceptable terms could have a material adverse effect on our business. We may be required to shut in wells due to lack of a market or inadequacy or unavailability of crude oil or natural gas pipelines, gathering systems or trucking capacity. A portion of our production may also be interrupted, or shut in, from time to time for numerous other reasons, including as a result of accidents, excessive pressures, maintenance, weather, field labor issues or other disruptions of service. Curtailments and disruptions may last from a few days to several months, and we have no control over when or if third-party facilities are restored.

In the past we have experienced production curtailments due to infrastructure and market constraints in the Eagle Ford shale formation, which has caused oil production to be shut in and natural gas production to be shut in or flared. Any significant curtailment in gathering, processing or pipeline system capacity, significant delay in the construction of necessary facilities or lack of availability of transportation would interfere with our ability to market our oil and natural gas production, and could have a material adverse effect on our cash flow and results of operations.

We have entered into significant natural gas firm transportation and marketing agreements primarily in East Texas and North Louisiana that require us to pay fixed amounts of money to the shippers or marketers regardless of quantities actually shipped or marketed. If we are unable to deliver the necessary quantities of natural gas, our results of operations and liquidity could be adversely affected.

We have entered into significant natural gas firm transportation contracts primarily in East Texas and North Louisiana that require us to pay fixed amounts of money to the shippers regardless of quantities actually shipped. The use of firm transportation agreements allows us priority space in a shippers' pipeline. Historically, we have paid significant amounts for the unused portion of these firm transportation agreements and expect to continue incurring significant costs for unused firm transportation in the future.

We have entered into an agreement to deliver an aggregate minimum volume commitment of natural gas production from the Holly and Shelby fields to certain gathering systems over a five-year period ending on December 1, 2018. If there is a shortfall to the minimum volume commitment in any year, then we are severally responsible with a joint venture partner to pay fixed amounts of money to the gatherer regardless of quantities actually produced in to the systems. For the twelve months ended December 1, 2015, our net share of the shortfall was $8.2 million and we remitted payment for this shortfall in January 2016.

In addition, we have also entered into a marketing agreement with respect to our Haynesville production whereby we are required to deliver a minimum amount of natural gas from the Haynesville shale. We will be required to make material expenditures for these agreements if we fail to deliver the required quantities of natural gas in the future.

We anticipate the deliveries of natural gas in future periods will not meet the minimum quantities set forth in certain of these agreements and will require us to make payments for the shortfall below the minimum quantities. In the event the quantities delivered under these arrangements are significantly below the minimum volumes within the agreements, it could adversely affect our business, financial condition and results of operations.

There are risks associated with our drilling activity that could impact our results of operations and financial condition. Our ability to develop properties in new or emerging formations may be subject to more uncertainties than drilling in areas that are more developed or have a longer history of established production.

Our drilling involves numerous risks, including the risk that we will not encounter commercially productive oil or natural gas reservoirs. We must incur significant expenditures to identify and acquire properties and to drill and complete wells. Additionally, seismic and other technology does not allow us to know conclusively prior to drilling a well that oil or natural gas is present or economically producible. The costs of drilling and completing wells are often uncertain, and drilling operations may be curtailed, delayed or canceled as a result of a variety of factors, including unexpected drilling conditions, pressure or irregularities in formations, equipment failures or accidents, weather conditions and shortages or delays in the delivery of equipment. We have experienced some delays in contracting for drilling rigs, obtaining fracture stimulation crews and materials, which result in increased costs to drill wells. Also, we may experience issues with the availability of water and sand used in our drilling and hydraulic fracturing activities. All of these risks could adversely affect our results of operations and financial condition.

The results of our drilling in new or emerging formations, including our properties in shale formations, are more uncertain initially than drilling results in areas that are developed, have established production or where we have a longer history of operation. Because new or emerging formations have limited or no production history, we are less able to use past drilling results in those areas to help predict future drilling results. Our experience with horizontal drilling in these areas to date, as well as the industry's drilling and production history, while growing, is limited. The ultimate success of these drilling and completion techniques will be better evaluated over time as more wells are drilled and production profiles are better established. We have implemented several initiatives to manage our base production and minimize the decline from our shale properties. If these initiatives are not successful and we are required to incur significant expenditures to manage our base production, this could negatively impact our production and cash flows from operations.

If our drilling results are less than anticipated or we are unable to execute our drilling program because of capital constraints, lease expirations, and/or natural gas and oil prices decline, our investment in these areas may not be as attractive as we anticipate and we could incur material impairments of undeveloped properties and the value of our undeveloped acreage could decline in the future, which could have a material adverse effect on our business and results of operations.

Certain of our undeveloped leasehold assets are subject to leases that will expire over the next several years unless production is established on the acreage.

Leases on oil and natural gas properties typically have a term after which they expire unless, prior to expiration, a well is drilled and production of hydrocarbons in paying quantities is established. If our leases expire and we are unable to renew the leases, we will lose our right to develop the related properties. While we seek to actively manage our leasehold inventory through drilling wells to hold the leasehold acreage that we believe is material to our operations, our drilling plans for these areas are subject to change.

We conduct a substantial portion of our operations through joint ventures, and our failure to continue such joint ventures or resolve any material disagreements with our partners could have a material adverse effect on the success of these operations, our financial condition and our results of operations. Furthermore, the actions taken by other working interest owners could prevent or alter our development plans.

We conduct a substantial portion of our operations through joint ventures with third parties, principally BG Group, plc and Kohlberg Kravis Roberts & Co. L.P. ("KKR"). We may also enter into other joint venture arrangements in the future. In many instances we depend on these third parties for elements of these arrangements that are important to the success of the joint venture, such as agreed payments of substantial development costs pertaining to the joint venture and their share of other costs of the joint venture. The performance of these third party obligations or the ability of third parties to meet their obligations under these arrangements is outside our control. If these parties do not meet or satisfy their obligations under these arrangements, the performance and success of these arrangements, and their value to us, may be adversely affected. If our current or future joint venture partners are unable to meet their obligations, we may be forced to undertake the obligations ourselves and/or incur additional expenses in order to have some other party perform such obligations. In such cases we may also be required to enforce our rights, which may cause disputes among our joint venture partners and us. If any of these events occur, they may adversely impact us, our financial performance and results of operations, these joint ventures and/or our ability to enter into future joint ventures.

Such joint venture arrangements may involve risks not otherwise present when exploring and developing properties directly, including, for example:

- our joint venture partners may share certain approval rights over major decisions;
- the possibility that our joint venture partners might become insolvent or bankrupt, leaving us liable for their shares of joint venture liabilities;
- the possibility that we may incur liabilities as a result of an action taken by our joint venture partners;
- joint venture partners may be in a position to take action contrary to our instructions or requests or contrary to our policies or objectives;
- disputes between us and our joint venture partners may result in litigation or arbitration, including the lawsuit filed against us by the affiliates of KKR described below, that would increase our expenses, delay or terminate projects and prevent our officers and directors from focusing their time and effort on our business;
- that under certain joint venture arrangements, neither joint venture partner may have the power to control the venture, and an impasse could be reached which might have a negative influence on our investment in the joint venture; and
- our joint venture partners may decide to terminate their relationship with us in any joint venture company or sell their interest in any of these companies and we may be unable to replace such joint venture partner or raise the necessary financing to purchase such joint venture partner's interest.

During the fourth quarter of 2015, our Eagle Ford joint venture partner purported to accept our third quarterly offer under the Participation Agreement to purchase interests in 21 gross (10.3 net) wells for $42.7 million, subject to purchase price adjustments subsequent to the effective date of June 30, 2015. We notified our joint venture partner that we do not intend to close this acquisition and our joint venture partner filed a petition for injunctive relief and damages alleging that, among other things, we breached our obligation under the Participation Agreement. The court denied our joint venture partner's motion for injunctive relief and their request to restrain us from disbursing proceeds from the production of the assets. We filed a counterclaim seeking a declaratory judgment that, among other things, we are not obligated to purchase the disputed wells as our partner's purported acceptance had not been received in a timely manner under the terms of the Participation Agreement. In addition, quarterly offers four and five are also now in dispute for various reasons. We cannot estimate or predict the outcome of the litigation with the our joint venture partner and we may not have sufficient funds or borrowing capacity under the EXCO Resources Credit Agreement to complete any acquisitions pursuant to the Participation Agreement or pay any damages for failure to complete a purchase that a court may determine, including the wells related to the claim by our joint venture partner. In the event we fail to purchase a group of wells that we are required to make an offer on, there are remedies available to our joint venture partner which allow them to reject our future offers, terminate the Participation Agreement, remove EXCO as the operator or pursue other legal remedies.

The failure to continue some of our joint ventures or to resolve disagreements with our joint venture partners, including the dispute subject to litigation with the KKR affiliates, could adversely affect our ability to transact the business that is the subject of such joint venture, including, with respect to the Participation Agreement, our ability to increase our assets in the Eagle Ford shale through acquisitions of KKR's producing properties. As a result, our financial condition and results of operations would be negatively affected.

The owners of working interests may not consent to the development of certain properties that we operate which may require us to assume their share of the working interest during the development and a period after the well is on production. This may require us to expend additional capital not already anticipated as part of our development plans and assume additional risks associated with the development and future performance of the properties. The owners of working interests in certain properties that we operate may also hold rights within the respective operating agreements that could prevent us from performing additional development activities on the properties such as recompletions and other workovers without their consent.

We may be unable to obtain additional financing to implement our growth strategy.

The growth of our business requires substantial capital on a continuing basis. Due to the amount of debt we have incurred and factors related to the depressed commodity price environment, we anticipate that it will be difficult for us in the foreseeable future to obtain additional equity or debt financing or to obtain additional secured financing other than purchase money indebtedness. If we are unable to obtain additional capital on satisfactory terms and conditions or at all, we may lose opportunities to acquire oil and natural gas properties and businesses and, therefore, be unable to implement our growth strategy.

We may be unable to acquire or develop additional reserves, which would reduce our revenues and access to capital.

Our success depends upon our ability to find, develop or acquire additional oil and natural gas reserves that are profitable to produce. Factors that may hinder our ability to acquire or develop additional oil and natural gas reserves include competition, access to capital, prevailing oil and natural gas prices and the number and attractiveness of properties for sale. If we are unable to conduct successful development activities or acquire properties containing Proved Reserves, our total Proved Reserves will generally decline as a result of production. Also, our production will generally decline. In addition, if our reserves and production decline, then the amount we are able to borrow under the EXCO Resources Credit Agreement will also decline. We may be unable to locate additional reserves, drill economically productive wells or acquire properties containing Proved Reserves.

Acquisitions, development drilling and exploratory drilling are the main methods of replacing reserves. However, development and exploratory drilling operations may not result in any increases in reserves for various reasons. Our future oil and natural gas production depends on our success in finding or acquiring additional reserves. If we fail to replace reserves through drilling or acquisitions, our level of production and cash flows will be adversely affected. The planned reduction in our development program in 2016 could negatively impact our ability to replace our reserves in the future.

We may not identify all risks associated with the acquisition of oil and natural gas properties, and any indemnification we receive from sellers may be insufficient to protect us from such risks, which may result in unexpected liabilities and costs to us.

Generally, it is not feasible for us to review in detail every individual property involved in an acquisition. Any future acquisitions will require an assessment of recoverable reserves, title, future oil and natural gas prices, operating costs, potential environmental hazards and liabilities, potential tax and liabilities under the Employee Retirement Income Security Act of 1974, as amended, other liabilities and similar factors. Ordinarily, our review efforts are focused on the higher-valued properties. Even a detailed review of properties and records may not reveal existing or potential problems, nor will it permit us to become sufficiently familiar with the properties to fully assess their deficiencies and capabilities. We do not inspect every well that we acquire. Potential problems, such as deficiencies in the mechanical integrity of equipment or environmental conditions that may require significant remedial expenditures, are not necessarily observable even when we inspect a well. Any unidentified problems from acquisitions could result in material liabilities and costs that could negatively impact our financial condition and results of operations.

Even if we are able to identify problems with an acquisition, the seller may be unwilling or unable to provide effective contractual protection or indemnify us against all or part of these problems. Even if a seller agrees to provide indemnification, the indemnification may not be fully enforceable and may be limited by floors and caps on such indemnification.

We may not correctly evaluate reserve data or the exploitation potential of properties as we engage in our acquisition, exploration, development and exploitation activities.

Our future success will depend on the success of our acquisition, exploration, development and exploitation activities. Our decisions to purchase, explore, develop or otherwise exploit properties or prospects will depend in part on the evaluation of data obtained from production reports and engineering studies, geophysical and geological analyses and seismic and other information, the results of which are often inconclusive and subject to various interpretations. These decisions could significantly reduce our ability to generate cash needed to service our debt and fund our capital program and other working capital requirements.

We may be unable to successfully integrate the operations of acquisitions with our operations and we may not realize all the anticipated benefits of any acquisitions.

Integration of our acquisitions with our business and operations has been a complex, time consuming and costly process. Failure to successfully assimilate our past or future acquisitions could adversely affect our financial condition and results of operations.

Our acquisitions involve numerous risks, including:

- operating a significantly larger combined organization and adding operations;
- difficulties in the assimilation of the assets and operations of the acquired business, especially if the assets acquired are in a new business segment or geographic area;
- the risk that oil and natural gas reserves acquired may not be of the anticipated magnitude or may not be developed as anticipated;
- the loss of significant key employees from the acquired business;

- the diversion of management's attention from other business concerns;
- the failure to realize expected profitability or growth;
- the failure to realize expected synergies and cost savings;
- coordinating geographically disparate organizations, systems and facilities; and
- coordinating or consolidating corporate and administrative functions.

Further, unexpected costs and challenges may arise whenever businesses with different operations or management are combined, and we may experience unanticipated delays in realizing the benefits of an acquisition. If we consummate any future acquisitions, our capitalization and results of operations may change significantly, and you may not have the opportunity to evaluate the economic, financial and other relevant information that we will consider in evaluating future acquisitions.

Our estimates of oil and natural gas reserves involve inherent uncertainty, which could materially affect the quantity and value of our reported reserves, our financial condition and the value of our common shares.

Numerous uncertainties are inherent in estimating quantities of Proved Reserves, including many factors beyond our control. This Annual Report on Form 10-K contains estimates of our Proved Reserves and the PV-10 and Standardized Measure of our Proved Reserves. These estimates are based upon reports of our independent petroleum engineers. These reports rely upon various assumptions, including assumptions required by the SEC as to oil and natural gas prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. These estimates should not be construed as the current market value of our estimated Proved Reserves.

The process of estimating oil and natural gas reserves is complex, requiring significant decisions and assumptions in the evaluation of available geological, engineering and economic data for each reservoir. As a result, the estimates are inherently imprecise evaluations of reserve quantities and future net revenue and such estimates prepared by different engineers or by the same engineers at different times, may vary substantially.

Our actual future production, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil and natural gas reserves may vary substantially from those we have assumed in the estimates. Any significant variance in our assumptions could materially affect the quantity and value of reserves, the amount of PV-10 and Standardized Measure described in this Annual Report on Form 10-K, and our financial condition. In addition, our reserves, the amount of PV-10 and Standardized Measure may be revised downward or upward, based upon production history, results of future exploitation and development activities, prevailing oil and natural gas prices, decisions and assumptions made by engineers and other factors. A material decline in prices paid for our production can adversely impact the estimated volumes and values of our reserves. Similarly, a decline in market prices for oil or natural gas may adversely affect our PV-10 and Standardized Measure. Any of these negative effects on our reserves or PV-10 and Standardized Measure may negatively affect the value of our common shares.

We currently have negative shareholders' equity, which could adversely affect our financial condition and otherwise adversely impact our business and growth prospects.

We have recently experienced losses as a result of the recent decline in oil and natural gas prices, and, as of December 31, 2015, we had negative shareholders' equity of $662.3 million, which means that our total liabilities exceeded our total assets. We may not be able to return to profitability in the near future, or at all, and the continuing existence of negative shareholders' equity may limit our ability to obtain future debt or equity financing or to pay future dividends or other distributions. If we are unable to obtain financing in the future, it could have a negative effect on our operations and our liquidity.

We are exposed to operating hazards and uninsured risks that could adversely impact our results of operations and cash flow.

Our operations are subject to the risks inherent in the oil and natural gas industry, including the risks of:

- fires, explosions and blowouts;
- pipe failures;
- abnormally pressured formations; and
- environmental accidents such as oil spills, natural gas leaks, ruptures or discharges of toxic gases, brine or well fluids into the environment (including groundwater contamination).

We have in the past experienced some of these events during our drilling, production and midstream operations. These events may result in substantial losses to us from:

- injury or loss of life;
- severe damage to or destruction of property, natural resources and equipment;
- pollution or other environmental damage;
- environmental clean-up responsibilities;
- regulatory investigation;
- penalties and suspension of operations; or
- attorneys' fees and other expenses incurred in the prosecution or defense of litigation.

As is customary in our industry, we maintain insurance against some, but not all, of these risks. Our insurance may not be adequate to cover these potential losses or liabilities. Furthermore, insurance coverage may not continue to be available at commercially acceptable premium levels or at all. Due to cost considerations, from time to time we have declined to obtain coverage for certain drilling activities. We do not carry business interruption insurance. Losses and liabilities arising from uninsured or under-insured events could require us to make large unbudgeted cash expenditures that could adversely impact our results of operations and cash flow.

Our operations may be interrupted by severe weather or drilling restrictions.

Our operations are conducted primarily in Texas, North Louisiana and Appalachia. The weather in these areas can be extreme and can cause interruption in our exploration and production operations. Severe weather can result in damage to our facilities entailing longer operational interruptions and significant capital investment.

Likewise, our operations are subject to disruption from earthquakes, hurricanes, winter storms and severe cold, which can limit operations involving fluids and impair access to our facilities. Additionally, many municipalities in Appalachia impose weight restrictions on the paved roads that lead to our jobsites due to the conditions caused by spring thaws.

We are subject to complex federal, state, local and other laws and regulations that could adversely affect the cost, manner or feasibility of conducting our operations.

Our oil and natural gas development and production 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 and local governmental authorities. We may incur substantial costs in order to comply with these existing laws and regulations. In addition, our costs of compliance may increase if existing laws and regulations are revised or reinterpreted, or if new laws and regulations become applicable to our operations. Our business is subject to federal, state and local laws and regulations as interpreted and enforced by governmental authorities possessing jurisdiction over various aspects of the exploration for, production and sale of, oil and natural gas. Failure to comply with such laws and regulations, as interpreted and enforced, could have a material adverse effect on our business, financial condition 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.

The Obama administration's budget proposals for fiscal year 2016 contain numerous proposed tax changes, and from time to time, legislation has been introduced that would enact many of these proposed changes. The proposed budget and legislation would repeal many tax incentives and deductions that are currently used by U.S. oil and natural gas companies and impose new fees. Among others, the provisions include: elimination of the ability to fully deduct intangible drilling costs in the year incurred; repeal of the percentage depletion deduction for oil and gas properties; repeal of the domestic manufacturing tax deduction for oil and natural gas companies; increase in the geological and geophysical amortization period for independent producers. The passage of legislation containing some or all of these provisions or any other similar change in U.S. federal income tax law could eliminate or postpone certain tax deductions that are currently available to us with respect to oil and natural gas exploration and development, and any such change could have a material adverse effect on our business, financial condition and results of operations.

Our ability to use net operating loss carryovers to reduce future tax payments may be limited.

Our net operating loss and other tax attribute carryovers ("NOLs") may be limited if we undergo an ownership change. Generally, an ownership change occurs if certain persons or groups increase their aggregate ownership in us by more than 50 percentage points looking back over a rolling three-year period. If an ownership change occurs, our ability to use our NOLs to reduce income taxes is limited to an annual amount, or the Section 382 limitation, equal to the fair market value of our common shares immediately prior to the ownership change multiplied by the long term tax-exempt interest rate, which is published monthly by the Internal Revenue Service ("IRS"). In the event of an ownership change, NOLs can be used to offset taxable income for years within a carryforward period subject to the Section 382 limitation. Any excess NOLs that exceed the Section 382 limitation in any year will continue to be allowed as carryforwards for the remainder of the carryforward period. Whether or not an ownership change occurs, the carryforward period for NOLs is 20 years from the year in which the losses giving rise to the NOLs were incurred. If the carryforward period for any NOL were to expire before that NOL had been fully utilized, the unused portion of that NOL would be lost. Our use of new NOLs arising after the date of an ownership change would not be affected by the Section 382 limitation (unless there is another ownership change after the new NOLs arise).

Our business exposes us to liability and extensive regulation on environmental matters, which could result in substantial expenditures.

Our operations are subject to numerous complex U.S. federal, state and local laws and regulations relating to the protection of the environment, including those governing the discharge of materials into the water and air, the generation, management and disposal of hazardous substances and wastes and the clean-up of contaminated sites. Laws, rules and regulations protecting the environment have changed frequently and the changes often include increasingly stringent requirements.

In general, the oil and natural gas exploration and production industry has been the subject of increasing scrutiny and regulation by environmental authorities. For example, the EPA has identified environmental compliance by the energy extraction section as one of its enforcement initiatives for 2014-2016 (and has solicited comments on continuing this initiative for fiscal years 2017 - 2019). Further, in September of 2015, the EPA issued a compliance alert stating that it has concerns regarding significant emissions from storage vessels, such as tanks or containers, at onshore oil and natural gas production facilities.

Compliance with environmental laws and regulations often increases our cost of doing business and, in turn, decreases our profitability. Failure to comply with these laws and regulations may result in the assessment of administrative, civil and criminal penalties, the incurrence of investigatory or remedial obligations, or the issuance of cease and desist orders. Any changes that result in more stringent or costly waste handling, storage, transport, disposal or cleanup requirements could require us to make significant expenditures to maintain compliance, and may otherwise have a material adverse effect on our earnings, results of operations, competitive position or financial condition. Changes to the requirements for drilling, completing, operating, and abandoning wells and related facilities could have similar adverse effects on us.

In addition, we could incur substantial expenditures complying with environmental laws and regulations, including future environmental laws and regulations which may be more stringent than those currently in effect. For example, the regulation of GHG emissions by the EPA or by various states in the areas in which we conduct business could have an adverse effect on our operations and demand for our oil and natural gas production. Moreover, the EPA has shown a general increased scrutiny on the oil and gas industry through its regulations under the CAA, SDWA, RCRA, TSCA and CWA.

The environmental laws and regulations to which we are subject may, among other things:

- require us to apply for and receive a permit before drilling commences or certain associated facilities are developed;
- restrict the types, quantities and concentrations of substances that can be released into the environment in connection with drilling, hydraulic fracturing, and production activities;
- limit or prohibit drilling activities on certain lands lying within wilderness, wetlands and other “waters of the United States,” threatened and endangered species habitats and other protected areas;
- require remedial measures to mitigate pollution from former operations, such as plugging abandoned wells;
- require additional control and monitoring devices on equipment; and
- impose substantial liabilities for pollution resulting from our operations.

Our operations may be impacted by upcoming regulatory changes, including proposed effluent limitation guidelines established by the EPA which could limit our ability to dispose of waste water from hydraulic fracturing activities into wastewater treatment systems. The EPA and state regulators are also reviewing the practices for the disposal of solid waste in surface impoundments from exploration and production facilities under Subtitle D of RCRA and may continue to refine those requirements. The EPA and state regulators are also expanding National Pollutant Discharge Elimination System permitting for storm water discharges at drilling sites. These actions may limit the options for disposal of hydraulic fracturing waste and increase costs associated with disposal.

In addition, on May 19, 2014, the EPA issued an Advanced Notice of Proposed Rulemaking seeking comment on the types of chemical mixtures used in hydraulic fracturing fluid which might be reported under the TSCA. This may require more extensive reporting obligations for oil and gas exploration activities that use hydraulic fracturing.

Moreover, as part of the Obama administration's continued focus on climate change, the EPA has outlined a series of actions to encourage reduction in methane and VOC emissions from the oil and gas industry. To this end, the EPA has adopted rules subjecting oil and natural gas operations to regulation under the NSPS, NESHAPS and programs under the CAA; imposing new and amended requirements under these programs for the control of VOCs. Among other things, the rules amend standards applicable to natural gas processing plants and expand the NSPS to include all oil and natural gas operations, imposing requirements on those operations. The rule also imposes NSPS standards for completions of hydraulically fractured natural gas wells. These standards include the reduced emission completion techniques. The NESHAPS also includes maximum achievable control technology standards for certain glycol dehydrators and storage vessels, and revises applicability provisions, alternative test protocols and the availability of the startup, shutdown and maintenance exemption. The implementation of these new requirements may result in increased operating and compliance costs, increased regulatory burdens and delays in our operations. There may also be further refinement to existing NSPS standards for VOCs as data is gathered about the implementation of those requirements.

Additionally, the EPA recently proposed an NSPS aimed at methane emissions from oil and natural gas operations.

Changes in regulation can also occur at a state or local level. For example, the State of Pennsylvania Department of Environmental Protection is updating oil and gas regulations which include more stringent permitting requirements, waste handling disposal and water restoration requirements. Some localities, for example in Texas, are enacting water usage restrictions that may impact oil and gas exploration. In addition, some states have considered, and notably California has adopted, a state specific GHG regulatory program that may limit GHG emissions or may require costs in association with the control of GHG emissions.

The implementation of climate change regulations could result in increased operating costs and reduced demand for our oil and natural gas production.

Although federal legislation regarding the control of emissions of GHGs for the present appears unlikely, the EPA has been implementing regulations under its existing CAA authority, and some of these regulations and proposed regulations may affect our operations. GHGs are certain gases, including carbon dioxide, a product of the combustion of natural gas, and methane, a primary component of natural gas, that may be contributing to the warming of the Earth's atmosphere, resulting in climatic changes. These GHG regulations could require us to incur increased operating costs and could have an adverse effect on demand for our oil and natural gas production.

In the absence of comprehensive federal legislation on GHG emission control, the EPA attempted to require the permitting of GHG emissions. Although the U.S. Supreme Court struck down GHG permitting requirements for GHG as a stand-alone pollutant, it upheld the EPA's authority to control GHG emissions when a source has to secure a major source permit to control the emissions of other criteria pollutants. The EPA established GHG reporting requirements for a broad range of sources, including in the petroleum and natural gas industry, requiring those sources to monitor, maintain records on, and annually report their GHG emissions. Although this rule does not limit the amount of GHGs that can be emitted, it requires us to incur costs to monitor record and report GHG emissions associated with our operations.

The Obama administration has also implemented a series of executive branch actions as part of its Climate Action Plan, the goal of which is to reduce GHGs in order to address the effects of global climate change. The Climate Action Plan has three main components: (i) cut carbon pollution (this includes GHGs and methane); (ii) prepare the U.S. for the impacts of climate change and (iii) lead efforts to combat global climate change. Another component of the administration's plan to cut carbon pollution is the development of an interagency strategy with the EPA, the DOI, the DOT, Department of Energy and Department of Labor to cut methane emissions. As part of this strategy, each federal agency is charged with promulgating new standards that may impact our operations by increasing costs and/or lowering demand for oil and natural gas.

As part of the directive to cut carbon pollution in the Climate Action Plan, the EPA proposed rules that would establish new air emission controls for emissions of methane from certain equipment and processes in the oil and natural gas source category, including production, processing, transmission and storage activities. The EPA's proposed rule package includes first-time standards to address emissions of methane from equipment and processes across the source category, including hydraulically fractured oil and natural gas well completions, fugitive emissions from well sites and compressors, equipment leaks at natural gas processing plants, and pneumatic pumps.

In addition, the rule would extend current VOC requirements established in 2012 to remaining unregulated equipment within the source category, such as hydraulically fractured oil well completions, fugitive emissions from well sites and compressor stations and pneumatic pumps. Another key component of the proposal is that it contemplates periodically monitoring methane emissions using imaging optical gas imaging instead of traditional observation methods.

Concurrent with this proposal, the EPA published another proposal to clarify the term "adjacent" in the definitions of: "building, structure, facility or installation" used to determine the "stationary source" for purposes of the Prevention of Significant Deterioration (PSD) and Nonattainment New Source Review (NNSR) programs and "major source" in the title V program as applied to the oil and natural gas sector. In this proposal, the EPA states that any oil and gas exploration facilities that have a common owner and that are "adjacent" to each other are a single source. The proposal offers two approaches for public comment on how "adjacent" should be defined. Although the EPA expresses a preference for defining "adjacency" in the oil and gas sector in terms of proximity, the EPA is also soliciting comment on an option to define "adjacency" in terms of "functional interrelatedness." The grouping together of sources may cause a group of sources to be treated as a "major source" and face enhanced regulation under federal environmental laws, including the Clean Air Act.

Federal and state legislation and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Hydraulic fracturing involves the injection of water, sand and chemicals under pressure into rock formations to stimulate natural gas production. Most hydraulic fracturing (other than hydraulic fracturing using diesel) is exempted from regulation under the SDWA. Congress has considered legislation to amend the federal SDWA to remove the exemption from regulation and permitting that is applicable to hydraulic fracturing operations and require reporting and disclosure of chemicals used by the oil and natural gas industry in the hydraulic fracturing process. Sponsors of bills previously introduced before the Senate and House of Representatives have asserted that chemicals used in the fracturing process could adversely affect drinking water supplies. Many states have adopted or are considering legislation regulating hydraulic fracturing, including the disclosure of chemicals used in the process. Such bills or similar legislation, if adopted, could increase the possibility of litigation and establish an additional level of regulation at the federal level that could lead to operational delays or increased operating costs and could result in additional regulatory burdens, making it more difficult to perform hydraulic fracturing and increasing our costs of compliance. At the state and local levels, some jurisdictions have adopted, and others are considering adopting, requirements that could impose more stringent permitting, public disclosure or well construction requirements on hydraulic fracturing activities, as well as bans on hydraulic fracturing activities. In the event that new or more stringent state or local legal restrictions relating to the hydraulic fracturing process are adopted in areas where we have properties, 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, the EPA has asserted federal regulatory authority over hydraulic fracturing using diesel under the SDWA's Underground Injection Control Program ("UIC"). Further, in June of 2015, the EPA released a draft assessment of the potential impacts of oil and gas hydraulic fracturing activities on the quality and quantity of drinking water resources in the United States for public comment and peer review by the Science Advisory Board. The public comment process for this assessment will conclude on October 30, 2016. The findings in this report may result in additional regulation and permitting requirements for oil and gas exploration. These may include additional restrictions on the disposal options for waste water, storm water and other wastes generated from hydraulic fracturing activities.

This draft assessment could result in additional regulatory scrutiny that could make it difficult to perform hydraulic fracturing and increase our costs of compliance and doing business. Consequently, these studies and initiatives could spur further legislative or regulatory action regarding hydraulic fracturing or similar production operations.

In addition, the EPA has issued guidance under the SDWA providing direction on how it will address the use of diesel in hydraulic fracturing activities and how its UIC program will be applied to such hydraulic fracturing activities. Moreover, the EPA has proposed new effluent limitations for the treatment and discharge of wastewater resulting from hydraulic fracturing activities. The EPA has also announced an initiative under the TSCA to develop regulations governing the disclosure and evaluation of hydraulic fracturing chemicals.

If these new effluent limitations are enacted it may increase our cost of disposal and impact our business operations. If hydraulic fracturing is regulated at the federal level at private drilling sites like it is now regulated on federal and tribal land, our hydraulic fracturing activities could become subject to additional permit requirements or operations restrictions which could lead to permitting delays and potential increases in costs. Restrictions on hydraulic fracturing could reduce the amount of oil and natural gas that we ultimately are able to produce.

Competition in our industry is intense and we may be unable to compete in acquiring properties, contracting for drilling equipment and hiring experienced personnel.

The oil and natural gas industry is highly competitive. We encounter strong competition from other independent operators and from major oil companies in acquiring properties, contracting for drilling equipment and securing trained personnel. Many of these competitors have greater financial and technical resources and a larger headcount than we do. As a result, our competitors may be able to pay more for desirable leases, or to evaluate, bid for and purchase a greater number of properties or prospects than our financial or personnel resources will permit. The oil and natural gas industry has periodically experienced shortages of drilling rigs, equipment, pipe and personnel, which has delayed development drilling and other exploitation activities and has caused significant expense/cost increases. We may experience difficulties in obtaining drilling rigs and other services in certain areas as well as an increase in the cost for these services and related material and equipment. We are unable to predict when, or if, such shortages may again occur or how such shortages and price increases will affect our development and exploitation program. Competition has also been strong in hiring experienced personnel, particularly in petroleum engineering, geoscience, accounting and financial reporting, tax and land professions. In addition, competition is strong for attractive oil and natural gas producing properties, oil and natural gas companies, and undeveloped leases and drilling rights. We are often outbid by competitors in our attempts to acquire properties or companies. All of these challenges could make it more difficult to execute our growth strategy.

Our use of derivative financial instruments is subject to risks that our counterparties may default on their contractual obligations to us and may cause us to forego additional future profits or result in us making cash payments.

To reduce our exposure to changes in the prices of oil and natural gas, we have entered into, and may in the future enter into, derivative financial instrument 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 derivative financial instruments are subject to mark-to-market accounting treatment. The change in the fair market value of these instruments is reported as a non-cash item in our consolidated statements of operations each quarter, which typically results in significant variability in our net income or loss. Derivative financial instruments expose us to the risk of financial loss and may limit our ability to benefit from increases in oil and natural gas prices in some circumstances, including the following:

- market prices may exceed the prices which we are contracted to receive, resulting in our need to make significant cash payments;
- there may be a change in the expected differential between the underlying price in the derivative financial instrument agreement and actual prices received; or
- the counterparty to the derivative financial instrument contract may default on its contractual obligations to us.

Our use of derivative financial instruments could have the effect of reducing our revenues and the value of our securities. During the year ended December 31, 2015 we received cash receipts from settlements on our derivative financial instrument contracts totaling $128.8 million and during the year ended December 31, 2014, we paid cash settlements of $19.0 million. For the year ended December 31, 2015, a $1.00 increase in the average commodity price per Mcfe would have resulted in an increase in cash settlement payments (or a decrease in settlements received) of approximately $56.5 million for oil and natural gas swaps. As of December 31, 2015, our oil and natural gas derivative financial instrument contracts were in the net asset position of $45.6 million. The ultimate settlement amount of these unrealized derivative financial instrument contracts is dependent on future commodity prices. We may incur significant realized and unrealized losses in the future from our use of derivative financial instruments to the extent market prices increase and our derivatives contracts remain in place.

We exist in a litigious environment.

Any constituent could bring suit regarding our existing or planned operations or allege a violation of an existing contract. Any such action could delay when planned operations can actually commence or could cause a halt to existing production until such alleged violations are resolved by the courts. Not only could we incur significant legal and support expenses in defending our rights, but halting existing production or delaying planned operations could impact our future operations and financial condition. In addition, we are defendants in numerous cases involving claims by landowners for surface or subsurface damages arising from our operations and for claims by unleased mineral owners and royalty owners for unpaid or underpaid revenues customary in our business. We incur costs in defending these claims and from time to time must pay damages or other amounts due. Such legal disputes can also distract management and other personnel from their primary responsibilities.

On December 15, 2015, certain affiliates of KKR filed a petition for injunctive relief and damages alleging that, among other things, EOC, a wholly owned subsidiary of EXCO, breached its obligation under the Participation Agreement to purchase the Q3 Wells from the KKR affiliates. For additional information, see "Item 3. Legal Proceedings."

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

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

There are inherent limitations in all internal control over financial reporting, and misstatements due to error or fraud may occur and not be detected.

While we have taken actions designed to address compliance with the internal control, disclosure control and other requirements of the Sarbanes-Oxley Act of 2002, as amended, and the rules and regulations promulgated by the SEC implementing these requirements, there are inherent limitations in our ability to control all circumstances. Our management, including our chief financial officer and chief accounting officer, does not expect that our internal controls and disclosure controls will prevent all errors and all fraud. A control system, no matter how well conceived and operated, can provide only reasonable, not absolute, assurance that the objectives of the control system are met. In addition, the design of a control system must reflect the fact that there are resource constraints and the benefit of controls must be relative to their costs. Because of the inherent limitations in all control systems, no evaluation of controls can provide absolute assurance that all control issues and instances of fraud, if any, in our company have been detected. These inherent limitations include the realities that judgments in decision-making can be faulty and that breakdowns can occur because of simple errors or mistakes. Further, controls can be circumvented by individual acts of some persons, by collusion of two or more persons, or by management override of the controls. The design of any system of controls also is based in part upon certain assumptions about the likelihood of future events, and there can be no assurance that any design will succeed in achieving its stated goals under all potential future conditions. Over time, a control may be inadequate because of changes in conditions, such as growth of our company or increased transaction volume, or the degree of compliance with the policies or procedures may deteriorate. Because of inherent limitations in a cost-effective control system, misstatements due to error or fraud may occur and not be detected.

We have engaged in transactions with related persons and may do so in the future. The terms of such transactions and the resolution of any conflicts that may arise may not always be in our or our shareholders' best interests.

We have engaged in transactions and may continue to engage in transactions with related persons. As described in our filings with the SEC, these transactions include, among others, issuances of securities to affiliates of certain of our directors, strategic consulting services provided to us by an affiliate of a director and the issuance of a term loan to us by an affiliate of a director. The resolution of any conflicts that may arise in connection with such related person transactions may not always be in our or our shareholders' best interests because the affiliates of such related persons may have the ability to influence the outcome of these conflicts.

Risks relating to our indebtedness

We have a substantial amount of indebtedness, which may adversely affect our cash flow and our ability to operate our business, remain in compliance with debt covenants and make payments on our debt.

As of December 31, 2015 we had approximately $1.1 billion of aggregate principal indebtedness, including $67.5 million of indebtedness subject to variable interest rates. Our total interest expense, excluding amortization of deferred financing costs, on an annual basis based on currently available interest rates would be approximately $70.5 million and would change by approximately $0.7 million for every 1% change in interest rates. Our total interest expense, as determined in accordance with GAAP, excludes the annual cash payments of $50.0 million on the Exchange Term Loan. See "Note 5. Debt" in the Notes to our Consolidated Financial Statements for additional information and the accounting treatment of the Exchange Term Loan.

Our level of debt could have important consequences, including the following:

- it may be more difficult for us to satisfy our obligations with respect to our indebtedness, and any failure to comply with the obligations of any of our debt agreements, including financial and other restrictive covenants, could result in an event of default under the EXCO Resources Credit Agreement, Second Lien Term Loans, the indenture governing the 2018 Notes and 2022 Notes ("Indenture"), and the agreements governing our other indebtedness;
- we may have difficulty borrowing money in the future for acquisitions (including any acquisition of interests in wells pursuant to the Participation Agreement with KKR), capital expenditures or to meet our operating expenses or other general corporate obligations;
- the amount of our interest expense may increase because certain of our borrowings are at variable rates of interest;
- we will need to use a substantial portion of our cash flows to pay principal and interest on our debt, which will reduce the amount of money we have for operations, working capital, capital expenditures, expansion, acquisitions or general corporate or other business activities;
- we may have a higher level of debt than some of our competitors, which may put us at a competitive disadvantage;
- we may be more vulnerable to economic downturns and adverse developments in our industry or the economy in general, especially declines in oil and natural gas prices;
- when oil and natural gas prices decline, our ability to maintain compliance with our financial covenants becomes more difficult and our borrowing base is subject to reductions, which may reduce or eliminate our ability to fund our operations; and
- our debt level could limit our flexibility in planning for, or reacting to, changes in our business and the industry in which we operate.

Our ability to meet our expenses and debt obligations will depend on our future performance, which will be affected by financial, business, economic, regulatory and other factors. We will be unable to control many of these factors, such as economic conditions and governmental regulation. The current low commodity price environment has had a significant, adverse impact on our business, including substantially reduced cash flows from operations due the decline in oil and natural gas prices and the roll off of our hedging arrangements. While we are not in default under our existing debt instruments, our ability to service our debt, including the 2018 Notes, 2022 Notes and Second Lien Term Loans, and fund our operations is at risk in a sustained continuation of the current commodity price environment. If the current low commodity price environment continues, we would need some additional form of debt restructuring, capital raising or asset sale in order to fund our operations and meet our substantial debt service obligations. Our management is actively pursuing additional strategies to improve our liquidity and reduce our future debt service obligations.

If we are unable to restructure our outstanding debt, obtain additional debt or equity financing, or raise adequate proceeds from sales of assets, we may not be able to make payments on our indebtedness, our secured lenders could foreclose against the assets securing their borrowings, and we may find it necessary to file a voluntary petition for reorganization relief under Chapter 11 of the Bankruptcy Code in order to provide us with additional time to identify an appropriate solution to our financial situation and implement a plan of reorganization aimed at improving our capital structure. Further, failing to comply with the financial and other restrictive covenants in the EXCO Resources Credit Agreement, the Indenture or the term loan agreements governing the Second Lien Term Loans could result in an event of default under such agreement, and any event of default may cause a default or accelerate our obligations with respect to our other outstanding indebtedness. A default or acceleration of our indebtedness would adversely affect our business, financial condition and results of operations.

We may incur substantially more debt, which may intensify the risks described above, including our ability to service our indebtedness.

Together with our subsidiaries, we may incur substantially more debt in the future in connection with our exploration, exploitation, development, acquisitions of undeveloped acreage and producing properties. The restrictions in our debt agreements on our incurrence of additional indebtedness are subject to a number of qualifications and exceptions, and under certain circumstances, indebtedness incurred in compliance with these restrictions could be substantial. Also, these restrictions do not prevent us from incurring obligations that do not constitute indebtedness. To the extent new indebtedness is added to our current indebtedness, the risks described above could substantially increase. Significant additions of undeveloped acreage financed with debt may result in increased indebtedness without any corresponding increase in borrowing base, which could curtail drilling and development of this acreage or could cause us to not comply with our debt covenants.

To service our indebtedness, fund our planned capital expenditure programs and fund acquisitions, we will require a significant amount of cash. Our ability to generate cash depends on many factors beyond our control, and any failure to meet our debt obligations could harm our business, financial condition and results of operations.

Our ability to make payments on and to refinance our indebtedness and to fund planned capital expenditures will depend on our ability to generate cash flow from operations and other resources in the future. This, to a certain extent, is subject to general economic, financial, competitive, legislative, regulatory and other factors that are beyond our control, including the prices that we receive for oil and natural gas.

Our business may not generate sufficient cash flow from operations and future borrowings may not be available to us in an amount sufficient to enable us to pay our indebtedness to fund planned capital expenditures or to fund our other liquidity needs. If our cash flow and capital resources are insufficient to fund our debt obligations and capital expenditure programs, we may be forced to sell assets, issue additional equity or debt securities or restructure our debt. These remedies may not be available on commercially reasonable terms, or at all. In addition, any failure to make scheduled payments of interest and principal on our outstanding indebtedness would likely result in a reduction of our credit rating, which could harm our ability to incur additional indebtedness on acceptable terms. Our cash flow and capital resources may be insufficient for payment of interest on and principal of our debt in the future, which could cause us to default on our obligations and could impair our liquidity.

Our borrowing base under the EXCO Resources Credit Agreement is subject to semi-annual redetermination, with the next scheduled redetermination set to occur in March 2016. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices. If our borrowing base were to be reduced to a level which was less than the current borrowings, we would be required to reduce our borrowings to a level sufficient to cure any deficiency. We may be required to sell assets or seek alternative debt or equity which may not be available at commercially reasonable terms, if at all.

In addition, we conduct certain of our operations through our joint ventures and subsidiaries. Accordingly, repayment of our indebtedness, including the 2018 Notes, 2022 Notes and the Second Lien Term Loans, is dependent on the generation of cash flow by our joint ventures and subsidiaries and their ability to make such cash available to us, by dividend, debt repayment or otherwise. Unless they are guarantors of the 2018 Notes, 2022 Notes, Second Lien Term Loans or our other indebtedness, our joint ventures and subsidiaries do not have any obligation to pay amounts due on the 2018 Notes and 2022 Notes, Second Lien Term Loans or our other indebtedness or to make funds available for that purpose. Our joint ventures and subsidiaries may not be able to, or may not be permitted to, make distributions to enable us to make payments in respect of our indebtedness. Each joint venture and subsidiary is a distinct legal entity, and, under certain circumstances, legal and contractual restrictions may limit our ability to obtain cash from our joint ventures and subsidiaries. While the Indenture, the term loan agreements governing the Second Lien Term Loans and the agreements governing certain of our other existing indebtedness limit the ability of certain of our joint ventures and subsidiaries to incur consensual restrictions on their ability to pay dividends or make other intercompany payments to us, these limitations are subject to qualifications and exceptions. In the event that we do not receive distributions from our joint ventures and subsidiaries, we may be unable to make required principal and interest payments on our indebtedness.

If we cannot make scheduled payments on our debt, we will be in default and holders of the 2018 Notes, 2022 Notes and the Second Lien Term Loans could declare all outstanding principal and interest to be due and payable, the lenders under the EXCO Resources Credit Agreement could terminate their commitments to loan money, our secured lenders could foreclose against the assets securing their borrowings and we could be forced into bankruptcy or liquidation. Our inability to generate sufficient cash flows to satisfy our debt obligations, or to refinance our indebtedness on commercially reasonable terms or at all, would materially and adversely affect our financial position and results of operations.

Restrictive debt covenants could limit our growth and our ability to finance our operations, fund our capital needs, respond to changing conditions and engage in other business activities that may be in our best interests.

The EXCO Resources Credit Agreement, the Indenture and the Second Lien Term Loans contain a number of significant covenants that, among other things, restrict our ability to:

- dispose of assets;
- incur or guarantee additional indebtedness and issue certain types of preferred shares;
- pay dividends on our capital stock;
- create liens on our assets;
- enter into sale or leaseback transactions;

- enter into specified investments or acquisitions;
- repurchase, redeem or retire our capital stock or subordinated debt;
- merge or consolidate, or transfer all or substantially all of our assets and the assets of our subsidiaries;
- engage in specified transactions with subsidiaries and affiliates; or
- pursue other corporate activities.

Also, the EXCO Resources Credit Agreement requires us to maintain compliance with certain financial covenants. Our ability to comply with these financial covenants may be affected by events beyond our control, and, as a result, we may be unable to meet these financial covenants. These financial covenants could limit our ability to obtain future financings, make needed capital expenditures, withstand a future downturn in our business or the economy in general or otherwise conduct necessary corporate activities. We may also be prevented from taking advantage of business opportunities that arise because of the limitations imposed on us by the restrictive covenants under the EXCO Resources Credit Agreement, the Indenture and the term loan agreements governing the Second Lien Term Loans. A breach of any of these covenants or our inability to comply with the required financial covenants could result in an event of default under the applicable indebtedness. When oil and/or natural gas prices decline for an extended period of time, our ability to comply with these covenants becomes more difficult. Although we are currently in compliance with these covenants, if oil and gas prices continue to decline, we may default on one or more of these covenants. Such a default, if not cured or waived, may allow the creditors to accelerate the related indebtedness and could result in acceleration of any other indebtedness to which a cross-acceleration or cross-default provision applies.

An event of default under the Indenture or the term loan agreements governing the Second Lien Term Loans would permit the lenders under the EXCO Resources Credit Agreement to terminate all commitments to extend further credit under the agreement. Furthermore, if we were unable to repay the amounts due and payable under the EXCO Resources Credit Agreement, those lenders could proceed against the collateral granted to them to secure that indebtedness. In the event that our lenders or noteholders accelerate the repayment of our borrowings, we and our subsidiaries may not have sufficient assets to repay that indebtedness. As a result of these restrictions, we may be:

- limited in how we conduct our business;
- unable to raise additional debt or equity financing during general economic, business or industry downturns; or
- unable to compete effectively or to take advantage of new business opportunities.

The term loan agreements governing the Second Lien Term Loans contain restrictive covenants that substantially limit our ability to incur additional indebtedness, which may limit our future sources of financing and our ability to raise additional capital to fund our operations.

The term loan agreements governing the Second Lien Term Loans contain restrictive covenants that, among other things, substantially limit our ability to incur additional indebtedness. See further details on these covenants in "Note 5. Debt" in the Notes to our Consolidated Financial Statements. These restrictive covenants may materially impact our ability to finance our operations, fund our capital needs or obtain additional financing on acceptable terms or at all. As a result, we may be unable to obtain funding for, among other things, future acquisitions, operating activities, capital expenditures or debt service requirements, which would have a material impact on our business and financial condition.

As a result of the Fairfax Term Loan, there may be an actual or apparent conflict of interest between Hamblin Watsa and a member of our Board of Directors.

Hamblin Watsa Investment Counsel Ltd. ("Hamblin Watsa"), a wholly owned subsidiary of Fairfax, is the administrative agent of the Fairfax Term Loan. Samuel A. Mitchell, a member of our Board of Directors, is a Managing Director of Hamblin Watsa and a member of Hamblin Watsa's investment committee, which consists of seven members that manage the investment portfolio of Fairfax. Additionally, based on filings with the Securities and Exchange Commission, Fairfax is the beneficial owner of approximately 9.0% of our outstanding common shares.

As a result, there may be an actual or apparent conflict of interest between Mr. Mitchell's duties to our company and Mr. Mitchell's duties to Hamblin Watsa, including, among other things, with respect to the fairness of the terms of the Fairfax Term Loan to EXCO. In accordance with the charter of the audit committee of our Board of Directors, our audit committee reviewed and pre-approved the terms of the Fairfax Term Loan as a potential related party transaction, and our Board of Directors determined that the terms of the Fairfax Term Loan were no less favorable to EXCO or our subsidiaries than those that could be obtained in arm's length dealings with non-affiliates, and, in the good faith judgment of our Board of Directors, no comparable transaction was available with which to compare the Fairfax Term Loan and the Fairfax Term Loan was fair, from a financial point of view, to EXCO.

Despite the approval of the terms of the Fairfax Term Loan, there can be no assurance that any actual or potential conflicts of interest between Mr. Mitchell's duties to EXCO and Mr. Mitchell's duties to Hamblin Watsa will be resolved in a manner that does not adversely affect our business, financial condition or results of operations. In addition, any actual or perceived conflict of interest may have a negative impact the value of our common shares.

We may not be able to repurchase or repay our indebtedness upon a change of control.

If we experience certain kinds of changes of control, we may be required to offer to repurchase or repay all or a portion of our existing indebtedness, including the 2018 Notes, 2022 Notes and the Second Lien Term Loans. We may not be able to repurchase or repay our indebtedness following a change of control because we may not have sufficient financial resources or sufficient access to financing.

A lowering or withdrawal of the ratings assigned to our debt securities by rating agencies may increase our future borrowing costs and reduce our access to capital.

Each of our 2018 Notes, 2022 Notes and Second Lien Term Loans currently has a non-investment grade rating, and any rating assigned could be lowered or withdrawn entirely by a rating agency if, in that rating agency's judgment, future circumstances relating to the basis of the rating, such as adverse changes, so warrant. Consequently, real or anticipated changes in the credit ratings of our 2018 Notes, 2022 Notes or Second Lien Term Loans will generally affect the market value of such debt. We have been informed by Standard & Poor's Rating Services and Moody's Investor Service, Inc. that our 2018 Notes, 2022 Notes and Second Lien Term Loans have been placed on a watch list for future downgrading.

Any future lowering of our ratings likely would make it more difficult or more expensive for us to obtain additional debt financing and may increase the cost of debt financing. In addition, if any credit rating initially assigned to the 2018 Notes, 2022 Notes or Second Lien Term Loans is subsequently lowered or withdrawn for any reason, it may have an adverse effect on the market price of such notes.

The credit risk of financial institutions could adversely affect us.

We have exposure to different counterparties, and we have entered into transactions with counterparties in the financial services industry, including commercial banks, investment banks, insurance companies and other institutions. These transactions expose us to credit risk in the event of default of our counterparty. Deterioration in the credit markets may impact the credit ratings of our current and potential counterparties and affect their ability to fulfill their existing obligations to us and their willingness to enter into future transactions with us. We have exposure to financial institutions in the form of derivative transactions in connection with our hedges and insurance companies in the form of claims under our policies. In addition, if any lender under the EXCO Resources Credit Agreement is unable to fund its commitment, our liquidity will be reduced by an amount up to the aggregate amount of such lender's commitment under the credit agreement.

Risks Relating to Our Common Shares

Our common share price may fluctuate significantly.

Our common shares trade on the NYSE but an active trading market for our common shares may not be sustained. The market price of our common shares could fluctuate significantly as a result of:

- announcements relating to our business or the business of our competitors;
- changes in expectations as to our future financial performance or changes in financial estimates of public market analysis;
- actual or anticipated quarterly variations in our operating results;
- conditions generally affecting the oil and natural gas industry;
- the success of our operating strategy; and
- the operating and share price performance of other comparable companies.

Many of these factors are beyond our control and we cannot predict their potential effects on the price of our common shares. In addition, the stock markets in general can experience considerable price and volume fluctuations.

If we fail to comply with the continued listing standards of the NYSE, it may result in a delisting of our common shares from the NYSE.

Our common shares are currently and have been listed for trading on the NYSE, and the continued listing of our common shares on the NYSE is subject to our compliance with a number of listing standards. To maintain compliance with these continued listing standards, the Company is required to maintain an average closing price of $1.00 or more over a consecutive 30 trading-day period. On July 30, 2015, we received a notice from the NYSE that the average closing price of our common shares over the prior 30 consecutive trading days was below $1.00 per share, and, as a result, the price per share of the common shares was below the minimum average closing price required to maintain listing on the NYSE. The notice stated that we had six months to regain compliance with the NYSE continued listing standards, or until January 30, 2016, or the NYSE would initiate procedures to suspend and delist the common shares. On November 2, 2015, we received a notice from the NYSE stating that we had regained compliance with the NYSE continued listing standards because the price of our common shares on October 30, 2015 and the average price of our common shares over the thirty trading days prior to October 30, 2015 exceeded $1.00 per share. On February 26, 2016 we received a second notice from the NYSE of our noncompliance with the continued listing standard. We intend to notify the NYSE of our intent to cure this noncompliance and are currently exploring options for regaining compliance, including a potential reverse share split of our common shares.

The price of our common shares is volatile and may fail to comply with the NYSE's minimum average closing price requirement in the future. If so, we may effect a reverse share split to regain compliance with NYSE listing standards. At a Special Meeting of Shareholders held on November 16, 2015, our shareholders authorized our Board of Directors to effect a reverse share split at a ratio of up to 1-for-10 common shares. The decision to effect a reverse share split and the exact ratio of the reverse share split will be made by our Board of Directors in its sole discretion. If we effect a reverse share split, the common shares will be deemed to be in compliance with NYSE standards if, promptly after the reverse share split, the price per common share exceeds $1.00 per share and remains above that level for at least the following 30 trading days.

Our amended and restated certificate of formation permits us to issue preferred shares that may restrict a takeover attempt that you may favor.

Our amended and restated certificate of formation permits our board to issue up to 10,000,000 preferred shares and to establish by resolution one or more series of preferred shares and the powers, designations, preferences and participating, optional or other special rights of each series of preferred shares. The preferred shares may be issued on terms that are unfavorable to the holders of our common shares, including the grant of superior voting rights, the grant of preferences in favor of preferred shareholders in the payment of dividends and upon our liquidation and the designation of conversion rights that entitle holders of our preferred shares to convert their shares into common shares on terms that are dilutive to holders of our common shares. The issuance of preferred shares in future offerings may make a takeover or change in control of us more difficult.

Holders of our common shares may experience future dilution.

We may in the future issue additional common shares or other securities convertible into, or exchangeable for, our common shares at prices that may not be the same price as holders of our common shares paid for their shares. We are currently authorized to issue up to 780,000,000 common shares and 10,000,000 preferred shares with such designations, preferences and rights as determined by our Board of Directors. We have an effective shelf registration statement from which additional common shares and other securities can be offered. The issuance of additional common shares may substantially dilute the ownership interests of our existing shareholders. Furthermore, sales of a substantial amount of our common shares in the public market, or the perception that these sales may occur, could reduce the market price of our common shares. This could also impair our ability to raise additional capital through the sale of our securities.

Our amended and restated certificate of formation contains a provision waiving the duty of a member of our Board of Directors to present corporate opportunities to us, which could adversely affect our shareholders.

Pursuant to our services and investment agreement with ESAS, we recently amended and restated our certificate of formation to provide that, C. John Wilder, a member of our Board of Directors, is not required to present corporate opportunities to us. As a result of the waiver, Mr. Wilder and certain of his affiliates have the ability to engage in the same or similar lines of business as us and will not be obligated to, among other things, offer us an opportunity to participate in any business opportunities that involve any aspect of the energy business or industry that are presented or become known to Mr. Wilder and certain of his affiliates. These potential conflicts of interest could have a material adverse effect on our business, financial condition and results of operations if attractive corporate opportunities are allocated by Mr. Wilder to himself or his affiliates instead of to us.

ESAS, Fairfax, Oaktree Capital Management, WL Ross & Co. LLC and/or their respective affiliates have significant influence over matters requiring shareholder approval because of their ownership of our common shares.

As of December 31, 2015, ESAS, Fairfax, Oaktree Capital Management, L.P. ("Oaktree"), and WL Ross & Co. LLC ("WL Ross"), directly or through certain affiliates, beneficially owned approximately 6.5%, 9.0%, 16.0% and 18.1%, respectively, of our outstanding common shares. In addition, ESAS owned warrants representing the right to purchase 80,000,000 of our common shares, which, if fully exercised, would increase ESAS' beneficial ownership of our outstanding common shares. Although these warrants are currently subject to exercise limitations, they may become exercisable in the future if our common shares achieve certain performance metrics compared to a peer group as of March 31, 2019.

The beneficial ownership of ESAS, Fairfax, Oaktree and WL Ross and/or their affiliates provides them with significant influence regarding matters submitted for shareholder approval, including proposals regarding:

- any merger, consolidation or sale of all or substantially all of our assets;
- the election of members of our Board of Directors; and
- any amendment to our articles of incorporation.

The current or increased ownership position of ESAS, Fairfax, Oaktree, WL Ross and/or their respective affiliates could delay, deter or prevent a change of control or adversely affect the price that investors might be willing to pay in the future for our common shares. The interests of ESAS, Fairfax, Oaktree, WL Ross, and/or their respective affiliates may significantly differ from the interests of our other shareholders and they may vote the common shares they beneficially own in ways with which our other shareholders disagree.

Item 1B. Unresolved Staff Comments

Not applicable.

Item 2. Properties

Corporate offices

We lease office space in Dallas, Texas and Cranberry Township, Pennsylvania. We also have small offices for technical and field operations in Texas, Louisiana, Pennsylvania and West Virginia. The table below summarizes our material corporate leases.

Location	Approximate square footage	Approximate monthly payment	Expiration
Dallas, Texas (1)	155,000	$ 246,000	May 31, 2025
Cranberry Township, Pennsylvania	15,400	$ 22,500	December 31, 2017

(1) The office lease in Dallas, Texas contains a right on our behalf to terminate the lease agreement early on June 30, 2020 or June 30, 2022.

Other

We have described our oil and natural gas properties, oil and natural gas reserves, acreage, wells, production and drilling activity in "Item 1. Business" of this Annual Report on Form 10-K.

Item 3. Legal Proceedings

In the ordinary course of business, we are periodically a party to various litigation matters. During the fourth quarter of 2015, our Eagle Ford joint venture partner purported to accept our third quarterly offer under the Participation Agreement to purchase interests in 21 gross (10.3 net) wells for $42.7 million, subject to purchase price adjustments subsequent to the effective date of June 30, 2015. We notified our joint venture partner that we did not intend to close this acquisition and, on December 15, 2015, our joint venture partner filed a petition for injunctive relief and damages in state district court in Harris County, Texas alleging that, among other things, we breached our obligation under the Participation Agreement. The petition seeks monetary damages and sought a temporary restraining order and temporary and permanent injunctions on our ability to collect and disburse the proceeds of production on the assets subject to the Participation Agreement. On January 4, 2016, the court denied our joint venture partner's motion for injunctive relief and their request to restrain us from disbursing proceeds from the production of the assets. On January 29, 2016, we filed a counterclaim seeking a declaratory judgment that, among other things, we are not obligated to purchase the disputed wells as our partner's purported acceptance had not been received in a timely manner under the terms of the Participation Agreement. In addition, quarterly offers four and five are also now in dispute for various reasons. We cannot estimate or predict the outcome of the litigation with the our joint venture partner and we may not have sufficient funds or borrowing capacity under the EXCO Resources Credit Agreement to complete any acquisitions pursuant to the Participation Agreement or pay any damages for failure to complete a purchase that a court may determine, including the wells related to the claim by our joint venture partner. In the event we fail to purchase a group of wells that we are required to make an offer on, there are remedies available to our joint venture partner which allow them to reject our future offers, terminate the Participation Agreement, remove EXCO as the operator or pursue other legal remedies.

Item 4. Mine Safety Disclosures

Not applicable.

PART II

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

Market information for our common shares

Our common shares trade on the NYSE under the symbol "XCO." The following table sets forth, for the periods indicated, the high and low sales prices per share of our common share as reported by the NYSE:

	Price per share		
	High	Low	Dividends Declared
2015			
First Quarter	$ 2.54	$ 1.29	$ —
Second Quarter	2.26	1.16	—
Third Quarter	1.17	0.48	—
Fourth Quarter	1.40	0.74	—
2014			
First Quarter	$ 5.85	$ 4.60	$ 0.05
Second Quarter	6.60	5.05	0.05
Third Quarter	5.95	3.25	0.05
Fourth Quarter	3.80	1.98	—

Our shareholders

According to our transfer agent, Continental Stock Transfer & Trust Company, there were 168 holders of record of our common shares on December 31, 2015 (including nominee holders such as banks and brokerage firms who hold shares for beneficial holders and holders of restricted shares).

NYSE compliance and proposed reverse share split

On July 30, 2015, we received a notice from the NYSE that the average closing price of our common shares over the prior 30 consecutive trading days was below $1.00 per share, and, as a result, the price per share of the common shares was below the minimum average closing price required to maintain listing on the NYSE. The notice stated that we had six months to regain compliance with the NYSE continued listing standards, or until January 30, 2016, or the NYSE would initiate procedures to suspend and delist the common shares. On November 2, 2015 EXCO was notified by the NYSE that it has regained compliance with the NYSE's continued listing standards because the price of our common shares on October 30, 2015, and the average price of our common shares over the thirty trading days prior to October 30, 2015 exceeded $1.00 per share.

On February 26, 2016 we received a second notice from the NYSE of our noncompliance with the continued listing standard. We intend to notify the NYSE of our intent to cure this noncompliance and are currently exploring options for regaining compliance, including a potential reverse share split of our common shares.

On November 16, 2015, at a Special Meeting of Shareholders, our shareholders approved a proposal that authorized the Board of Directors to effect a reverse share split at a ratio of up to 1-for-10 common shares with the decision, timing and exact ratio of the reverse share split to be determined by the Board of Directors in its sole discretion. In making its determination, the Board of Directors would consider, among other things, whether effecting the reverse share split is necessary or desirable to maintain the listing of the common shares on the NYSE at that time and in the future.

If our Board of Directors decides to effect the reverse share split, it will reduce the total number of our issued and outstanding common shares, including shares held by the Company as treasury shares, and the number of common shares each of our shareholders owns will be reduced in proportion to the reverse share split ratio. The proposed reverse share split would affect all shareholders uniformly and would not affect any shareholder's percentage ownership of the company. Our past and future earnings (losses) per share, and any dividends paid on our common shares, would be proportionately adjusted in our future financial statements if the reverse share split is effected.

Our dividend policy

On December 15, 2014, our Board of Directors suspended our cash dividend to provide additional funds to reinvest into the Company. The indentures governing our 2018 Notes and 2022 Notes and the agreements governing the Second Lien Term Loans contain covenants that limit our ability to pay dividends. Any future declaration of dividends, as well as the establishment of record and payment dates, will depend on, among other things, our earnings, capital requirements, financial condition, prospects and other factors our Board of Directors may deem relevant.

Issuer repurchases of common shares

The following table details our repurchases of common shares for the three months ended December 31, 2015:

Period	Total Number of Shares Purchased	Average Price Paid Per Share	Total Number of Shares Purchased as Part of Publicly Announced Plans or Programs	Maximum Approximate Dollar Value of Shares that May Yet Be Purchased Under the Plans or Programs (in millions) (1)
October 1 - October 31	—	$ —	—	$ 192.5
November 1 - November 30	—	—	—	192.5
December 1 - December 31	—	—	—	192.5
Total	—	—	—	

(1) On July 19, 2010, we announced a $200.0 million share repurchase program.

Item 6. Selected Financial Data

The following table presents our selected historical financial and operating data. This financial data should be read in conjunction with “Item 7. Management's Discussion and Analysis of Financial Condition and Results of Operations,” our consolidated financial statements, the notes to our consolidated financial statements and the other financial information included in this Annual Report on Form 10-K. This information does not replace the consolidated financial statements.

Selected consolidated financial and operating data

(in thousands, except per share amounts)	Year Ended December 31, 2015	2014	2013	2012	2011
Statement of operations data (1):					
Revenues:					
Oil and natural gas	$ 328,331	$ 660,269	$ 634,309	$ 546,609	$ 754,201
Cost and expenses:					
Oil and natural gas production (2)	76,533	94,326	83,248	104,610	108,641
Gathering and transportation	99,321	101,574	100,645	102,875	86,881
Depletion, depreciation and amortization	215,426	263,569	245,775	303,156	362,956
Impairment of oil and natural gas properties	1,215,370	—	108,546	1,346,749	233,239
Accretion of discount on asset retirement obligations	2,277	2,690	2,514	3,887	3,652
General and administrative (3)	58,818	65,920	91,878	83,818	104,618
(Gain) loss on divestitures and other operating items (4)	461	5,315	(177,518)	17,029	23,819
Total cost and expenses	1,668,206	533,394	455,088	1,962,124	923,806
Operating income (loss)	(1,339,875)	126,875	179,221	(1,415,515)	(169,605)
Other income (expense):					
Interest expense, net	(106,082)	(94,284)	(102,589)	(73,492)	(61,023)
Gain (loss) on derivative financial instruments (5)	75,869	87,665	(320)	66,133	219,730
Gain on restructuring and extinguishment of debt (6)	193,276	—	—	—	—
Other income (expense)	122	241	(828)	969	788
Equity income (loss) (7)	(15,691)	172	(53,280)	28,620	32,706
Total other income (expense)	147,494	(6,206)	(157,017)	22,230	192,201
Income (loss) before income taxes	(1,192,381)	120,669	22,204	(1,393,285)	22,596
Income tax expense	—	—	—	—	—
Net income (loss)	$(1,192,381)	$ 120,669	$ 22,204	$(1,393,285)	$ 22,596
Basic net income (loss) per share	$ (4.36)	$ 0.45	$ 0.10	$ (6.50)	$ 0.11
Diluted net income (loss) per share	$ (4.36)	$ 0.45	$ 0.10	$ (6.50)	$ 0.10
Cash dividends declared per share	$ —	$ 0.15	$ 0.20	$ 0.16	$ 0.16
Weighted average common shares and common share equivalents outstanding:					
Basic	273,621	268,258	215,011	214,321	213,908
Diluted	273,621	268,376	230,912	214,321	216,705
Statement of cash flow data:					
Net cash provided by (used in):					
Operating activities	$ 134,027	$ 362,093	$ 350,634	$ 514,786	$ 428,543
Investing activities	(300,833)	(221,588)	(252,478)	(427,094)	(709,531)
Financing activities	132,748	(144,683)	(93,317)	(74,045)	268,756
Balance sheet data (8):					
Current assets	$ 149,801	$ 330,766	$ 305,854	$ 361,866	$ 678,008
Total assets	954,126	2,304,942	2,399,836	2,313,072	3,779,060
Current liabilities	252,919	329,436	349,170	237,931	287,399
Long-term debt	1,320,279	1,430,516	1,850,120	1,838,312	1,875,301
Shareholders' equity	(662,323)	510,004	147,905	149,393	1,558,332
Total liabilities and shareholders' equity	954,126	2,304,942	2,399,836	2,313,072	3,779,060

(1) We have completed numerous acquisitions and dispositions which impact the comparability of the selected financial data between periods.
(2) Equity-based compensation calculated pursuant to FASB ASC 718, *Compensation-Stock Compensation* ("ASC 718") included in oil and natural gas production costs was $0.1 million for the year ended December 31, 2011. We had no equity-based compensation included in oil and natural gas production costs for the years ended December 31, 2015, 2014, 2013 and 2012.
(3) Equity-based compensation included in general and administrative expenses was $7.2 million, $5.0 million, $10.7 million, $8.9 million and $10.9 million for the years ended December 31, 2015, 2014, 2013, 2012 and 2011, respectively.
(4) During 2013, we recognized a gain on the contribution of properties to Compass Production Partners, L.P. ("Compass").
(5) We do not designate our derivative financial instruments as hedges and, as a result, the changes in the fair value of our derivative financial instruments are recognized in our Consolidated Statements of Operations. See "Note 2. Summary of significant accounting policies" in the Notes to our Consolidated Financial Statements for a description of this accounting method.
(6) During 2015, we recognized a gain on restructuring and extinguishment of debt as a result of repurchasing a portion of our 2018 Notes and 2022 Notes in exchange for the holders of such notes agreeing to act as lenders in connection with the Exchange Term Loan. In addition, we repurchased a portion of the 2018 Notes in open market purchases which resulted in a gain on extinguishment of debt. See "Note 5. Debt" in the Notes to our Consolidated Financial Statements for further discussion.
(7) On November 15, 2013, we sold our equity interest in TGGT Holdings, LLC ("TGGT") to Azure in exchange for cash proceeds and an equity interest in Azure Midstream Holdings LLC ("Azure"). We report our equity interest acquired in Azure using the cost method of accounting.
(8) Adoption of Accounting Standard Update "ASU" No. 2015-17, Income Taxes (Topic 740): *Balance Sheet Classification of Deferred Taxes* ("ASU 2015-17") and ASU No. 2015-03, Interest - Imputation of Interest (Subtopic 835-30): *Simplifying the Presentation of Debt Issuance Costs* ("ASU 2015-03") in the fourth quarter of 2015 resulted in certain reclassifications of prior period information. See "Note. 2. Summary of significant accounting policies" in the Notes to our Consolidated Financial Statements for additional information.

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

The following management's discussion and analysis of our financial condition and results of operations should be read in conjunction with our financial statements and the related notes to those statements included elsewhere in this Annual Report on Form 10-K. In addition to historical financial information, the following management's discussion and analysis contains forward-looking statements that involve risks, uncertainties and assumptions. Our results and the timing of selected events may differ materially from those anticipated in these forward-looking statements as a result of many factors, including those discussed under "Item 1A. Risk Factors" and elsewhere in this Annual Report on Form 10-K.

Overview and history

We are an independent oil and natural gas company engaged in the exploration, exploitation, acquisition, development and production of onshore U.S. oil and natural gas properties with a focus on shale resource plays. Our principal operations are conducted in certain key U.S. oil and natural gas areas including Texas, Louisiana and the Appalachia region.

Our primary strategy focuses on the exploitation and development of our shale resource plays and the pursuit of leasing and undeveloped acreage acquisition opportunities in Texas and Louisiana. We plan to carry out this strategy by executing on a strategic plan that incorporates the following three core objectives: (i) restructuring the balance sheet to enhance our business and extend structural liquidity; (ii) transforming EXCO into the lowest cost producer; and (iii) optimizing and repositioning the portfolio. We believe this strategy will allow us to create long-term value for our shareholders.

Like all oil and natural gas exploration and production companies, we face the challenge of natural production declines. We attempt to offset the impact of this natural decline by implementing drilling and exploitation projects to identify and develop additional reserves and adding reserves through leasing and undeveloped acreage acquisition opportunities.

Recent developments

Second Lien Term Loans and note repurchases

On October 26, 2015, we closed a 12.5% senior secured second lien term loan with certain affiliates of Fairfax Financial Holdings Limited ("Fairfax") in the aggregate principal amount $300.0 million ("Fairfax Term Loan"). The proceeds from the

Fairfax Term Loan were used to repay outstanding indebtedness under the EXCO Resources Credit Agreement. We also closed a 12.5% senior secured second lien term loan with certain unsecured noteholders in the aggregate principal amount of $291.3 million on October 26, 2015 and $108.7 million on November 4, 2015 (“Exchange Term Loan,” and together with the Fairfax Term Loan, “Second Lien Term Loans”). The proceeds from the Exchange Term Loan were utilized to repurchase an aggregate $551.2 million principal amount of the outstanding 7.5% senior unsecured notes due September 15, 2018 ("2018 Notes") and $277.2 million principal amount of the outstanding 8.5% senior unsecured notes due April 15, 2022 ("2022 Notes") in exchange for the holders of such notes agreeing to act as lenders in connection with the Exchange Term Loan.

Additionally, in the fourth quarter of 2015, we repurchased $40.8 million in principal amount of the 2018 Notes through open market purchases with $12.0 million in cash. The exchange and the open market repurchase resulted in a $193.3 million net gain included in Gain on restructuring and extinguishment of debt in our Consolidated Statements of Operations. Since December 31, 2015, we have purchased an additional $9.5 million of 2018 Notes and $39.9 million of 2022 Notes with $6.7 million in cash. The 2018 Notes and 2022 Notes repurchased will be canceled by the trustee following customary settlement procedures. See further discussion of the Second Lien Term Loans and the 2018 Notes and 2022 Notes repurchases in "Note 5. Debt" in the Notes to our Consolidated Financial Statements.

EXCO Resources Credit Agreement amendments

On February 6, 2015, we amended the EXCO Resources Credit Agreement to include, among other things, a ratio of consolidated EBITDAX to consolidated interest expense, as determined in accordance with GAAP, ("Interest Coverage Ratio") and a ratio of senior secured indebtedness, excluding Second Lien Term Loans and any other indebtedness subordinated to the EXCO Resources Credit Agreement, to consolidated EBITDAX ("Senior Secured Indebtedness Ratio"). On July 27, 2015, the EXCO Resources Credit Agreement was amended to include modifications to our financial covenants, interest rate grid and borrowing base if we issue certain indebtedness subordinated to the EXCO Resources Credit Agreement. On October 19, 2015, we amended the EXCO Resources Credit Agreement which, among other things, decreased our borrowing base to $375.0 million effective with the issuance of the Second Lien Term Loans. In addition, our interest rate grid increased by 50 bps, the Interest Coverage Ratio was modified to require that we maintain a ratio of at least 1.25 to 1.00 as of the end of any fiscal quarter and our leverage ratio (as defined in the EXCO Resources Credit Agreement) was terminated. The next scheduled borrowing base redetermination for the EXCO Resources Credit Agreement is set to occur in March 2016. See "Note 5. Debt" in the Notes to our Consolidated Financial Statements for a more detailed discussion.

Appointment of Chief Executive Officer and Chief Operating Officer

On March 31, 2015, our Board of Directors appointed Harold L. Hickey to the position of President and Chief Executive Officer of EXCO. Mr. Hickey previously served as EXCO's President and Chief Operating Officer since February 2013 and Chief Operating Officer since October 2005.

On April 17, 2015, our Board of Directors appointed Harold H. Jameson to the position of Chief Operating Officer of EXCO. Mr. Jameson most recently served as EXCO’s Vice President of Development and Production with primary responsibilities including the horizontal shale development drilling programs in our Haynesville, Eagle Ford and Marcellus assets. Mr. Jameson has served in a Vice President role at EXCO since March 2011.

Services and Investment Agreement

On March 31, 2015, we entered into a four year services and investment agreement with ESAS. As part of this agreement, ESAS will provide certain strategic advisory services including the development and execution of a strategic improvement plan. On September 8, 2015, we entered into an amendment to the agreement and closed the transactions contemplated by the agreement. At the closing, C. John Wilder, Executive Chairman of Bluescape, was appointed as a member of our Board of Directors and as the Executive Chairman of the Board of Directors. Pursuant to the amended agreement:

- ESAS purchased 5,882,353 common shares from EXCO at a price of $1.70 per share on September 8, 2015;
- ESAS agreed to purchase additional common shares of EXCO through open market purchases such that ESAS will own common shares of EXCO with an aggregate cost basis of at least $23.5 million as of the first anniversary of the closing date, subject to certain extensions and exceptions. ESAS completed the required investment on December 31, 2015 by purchasing a total 12,464,130 common shares during the fourth quarter of 2015. As of December 31, 2015, ESAS owned common shares of EXCO with an aggregate cost basis of $23.5 million.
- EXCO agreed to pay ESAS a monthly fee of $300,000 for the term of the agreement;
- EXCO agreed to pay ESAS an annual incentive payment of up to $2.4 million per year based on the price of our common shares achieving certain performance hurdles as compared to a peer group; and

- EXCO issued to ESAS warrants to purchase an aggregate of 80,000,000 common shares with exercise prices ranging from $2.75 to $10.00 per share. The warrants vest on March 31, 2019 and their exercisability is subject to EXCO's common share price achieving certain performance hurdles as compared to the peer group. On August 18, 2015, EXCO's shareholders approved, among other things, the increase to the authorized number of common shares available for issuance to 780,000,000 which ensures that an adequate number of common shares are available for issuance, including the shares to be reserved for issuance under the warrants issued to ESAS.

For a more detailed discussion of this agreement, see "Note. 11. Equity-based compensation" and "Note 13. Related party transactions" in the Notes to our Consolidated Financial Statements.

Critical accounting estimates

The process of preparing financial statements in conformity with GAAP requires us to make estimates and assumptions to determine reported amounts of certain assets, liabilities, revenues, expenses and related disclosures. We have identified the most critical accounting policies used in the preparation of our consolidated financial statements. We determined the critical policies by considering accounting policies that involve the most complex or subjective decisions or assessments. We identified our most critical accounting policies to be those related to our estimates of Proved Reserves, derivative financial instruments, business combinations, equity-based compensation, oil and natural gas properties, goodwill, revenue recognition, asset retirement obligations and income taxes.

The following is a discussion of our most critical accounting estimates, judgments and uncertainties that are inherent in our application of GAAP. For a more complete discussion of our accounting policies see "Note 2. Summary of significant accounting policies" in the Notes to our Consolidated Financial Statements.

Estimates of Proved Reserves

The Proved Reserves data included in this Annual Report on Form 10-K was prepared in accordance with SEC guidelines. The accuracy of a reserve estimate is a function of:

- the quality and quantity of available data;
- the interpretation of this data;
- the accuracy of various mandated economic assumptions; and
- the technical qualifications, experience and judgment of the persons preparing the estimates.

Because these estimates depend on many assumptions, all of which may substantially differ from actual results, reserve estimates may be different from the quantities of oil and natural gas that are ultimately recovered. In addition, results of drilling, testing and production after the date of an estimate may justify material revisions to the estimate. The assumptions used for our shale properties including reservoir characteristics and performance are subject to further refinement as additional production history is accumulated.

You should not assume that the present value of future net cash flows represents the current market value of our estimated Proved Reserves. In accordance with the SEC's requirements, we based the estimated discounted future net cash flows from Proved Reserves according to the requirements in the SEC's Release No. *33-8995 Modernization of Oil and Gas Reporting*. Actual future prices and costs may be materially higher or lower than the prices and costs used in the preparation of the estimate. Further, the mandated discount rate of 10% may not be an accurate assumption of future interest rates or cost of capital.

Proved Reserve quantities directly and materially impact depletion expense. If the Proved Reserves decline, then the rate at which we record depletion expense increases, reducing net income. A decline in the estimate of Proved Reserves may result from lower market prices, making it uneconomical to drill or produce from higher cost fields. In addition, a decline in Proved Reserves may impact the outcome of our assessment of our oil and natural gas properties and require an impairment of the carrying value of our oil and natural gas properties.

Business combinations

When we acquire assets that qualify as a business, we use FASB ASC 805-10, *Business Combinations ("*ASC 805-10") to record our acquisitions of oil and natural gas properties or entities. ASC 805-10 requires that acquired assets, identifiable intangible assets and liabilities be recorded at their fair value, with any excess purchase price being recognized as goodwill. Application of ASC 805-10 requires significant estimates to be made by management using information available at the time of acquisition. Since these estimates require the use of significant judgment, actual results could vary as the estimates are subject to changes as new information becomes available.

Derivative financial instruments

We use derivative financial instruments to manage price fluctuations, protect our investments and achieve a more predictable cash flow. The estimates of the fair values of our derivative financial instruments require judgment. The fair value of our derivative financial instruments is determined by quoted futures prices, utilization of the credit-adjusted risk-free rate curves and the implied rates of volatility. We do not designate our derivative financial instruments as hedging instruments for financial accounting purposes and, as a result, we recognize the change in the respective instruments' fair value in earnings. When prices for oil and natural gas are volatile, a significant portion of the effect of our derivative financial instrument management activities consists of non-cash income or expense due to changes in the fair value of our derivative financial instruments.

Equity-based compensation

Our equity-based compensation includes share-based compensation to employees which we account for in accordance with ASC 718 and equity-based compensation for warrants issued to ESAS which we account for in accordance with FASB ASC Topic 505-50, *Equity-Based Payments to Non-Employees* ("ASC 505-50").

ASC 718 requires share-based compensation to employees to be recognized in our Consolidated Statements of Operations based on their estimated fair values. Estimating the grant date fair value of our share-based compensation requires management to make assumptions and to apply judgment in estimating the fair value. These assumptions and judgments include estimating the volatility of our share price, dividend yields, expected term, forfeiture rates and other company-specific inputs. ASC 505-50 requires the warrants to be re-measured each interim reporting period until the completion of the services under the agreement and an adjustment is recorded in our Consolidated Statements of Operations. The fair value of the warrants is dependent on factors such as our share price, historical volatility, risk-free rate and performance relative to our peer group.

Changes in these assumptions could materially affect the estimate of the fair value. If actual results are not consistent with the assumptions used, the equity-based compensation expense reported in our financial statements may not be representative of the actual economic impact of the equity-based compensation.

Oil and natural gas properties

The accounting for, and disclosure of, oil and natural gas producing activities require that we choose between two GAAP alternatives: the full cost method or the successful efforts method. We use the full cost method of accounting, which involves capitalizing all acquisition, exploration, exploitation and development costs of oil and natural gas properties. Once we incur costs, they are recorded in the depletable pool of proved properties or in unproved properties, collectively, the full cost pool. Our unproved property costs are not subject to depletion. We review our unproved oil and natural gas property costs on a quarterly basis to assess for impairment or the need to transfer unproved costs to proved properties as a result of extension or discoveries from drilling operations or determination that no proved reserves are attributable to such costs. In determining whether such costs should be impaired or transferred, we evaluate lease expiration dates, recent drilling results, future development plans and current market values. Our undeveloped properties are predominantly held-by-production, which reduces the risk of impairment as a result of lease expirations. We expect these costs to be evaluated in one to seven years and transferred to the depletable portion of the full cost pool during that time.

We capitalize interest on the costs related to the acquisition of undeveloped acreage in accordance with FASB ASC 835-20*, Capitalization of Interest*. When the unproved property costs are moved to proved developed and undeveloped oil and natural gas properties, or the properties are sold, we cease capitalizing interest related to these properties.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool, excluding the book value of unproved properties, and all estimated future development costs less estimated salvage value are divided by the total estimated quantities of Proved Reserves. This rate is applied to our total production for the quarter, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs, including share-based compensation, that is attributable to our acquisition, exploration, exploitation and development activities.

Sales, dispositions and other oil and natural gas property retirements are accounted for as adjustments to the full cost pool, with no recognition of gain or loss, unless the disposition would significantly alter the amortization rate and/or the relationship between capitalized costs and Proved Reserves.

Pursuant to Rule 4-10(c)(4) of Regulation S-X, at the end of each quarterly period, companies that use the full cost method of accounting for their oil and natural gas properties must compute a limitation on capitalized costs ("ceiling test"). The ceiling test involves comparing the net book value of the full cost pool, after taxes, to the full cost ceiling limitation defined below. In the event the full cost ceiling limitation is less than the full cost pool, we are required to record a ceiling test impairment of our oil and natural gas properties. The full cost ceiling limitation is computed as the sum of the present value of estimated future net revenues from our Proved Reserves by applying the average price as prescribed by the SEC Release No. 33-8995, less estimated future expenditures (based on current costs) to develop and produce the Proved Reserves, discounted at 10%, plus the cost of properties not being amortized and the lower of cost or estimated fair value of unproved properties included in the costs being amortized, net of income tax effects.

The ceiling test is computed using the simple average spot price for the trailing 12 month period using the first day of each month. Each of the reference prices for oil and natural gas are further adjusted for quality factors and regional differentials to derive estimated future net revenues. Under full cost accounting rules, any ceiling test impairments of oil and natural gas properties may not be reversed in subsequent periods. Since we do not designate our derivative financial instruments as hedging instruments, we are not allowed to use the impacts of the derivative financial instruments in our ceiling test computations.

The evaluation of impairment of our oil and natural gas properties includes estimates of Proved Reserves. There are numerous uncertainties inherent in estimating quantities of Proved Reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revisions of such estimate. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

Goodwill

In accordance with FASB ASC 350-20, *Intangibles-Goodwill and Other*, goodwill is not amortized, but is tested for impairment on an annual basis as of December 31, or more frequently as impairment indicators arise. Impairment tests involve the use of estimates related to the fair market value of the business operations with which goodwill is associated. Losses, if any, resulting from impairment tests will be reflected in operating income in the Consolidated Statements of Operations.

We apply a two-part, equally weighted approach in determining the fair value of our business as part of the goodwill impairment test. We perform an income approach, which uses a discounted cash flow model to value our business, and a market approach, in which our value is determined using trading metrics and transaction multiples of peer companies. The discounted cash flow model used in the income approach requires us to make various judgmental assumptions about future production, revenues, operating and capital expenditures, discount rates and other inputs which are based on our budgets, business plans, economic projections and anticipated future cash flows. The market approach requires us to make assumptions regarding the identifications of comparable companies and transactions as well as the future performance of ourselves and the comparable companies. We consider our enterprise value to be the combined market capitalization plus the fair value of our debt in determining the fair value of our reporting unit and to corroborate and conform the results with the valuation model. Due to the changing market conditions, it is possible that inputs and assumptions used in the valuation may change in the future, which could materially affect the estimate of the fair value of our business. Our enterprise value significantly decreased subsequent to December 31, 2015, which could lead to an impairment of goodwill in future periods. For example, a 30% decrease in our enterprise value, without a change in other assumptions, would have caused our enterprise value to be below the carrying value of our net assets. This would have required us to perform step two of the goodwill impairment test and could have resulted in an impairment of goodwill at December 31, 2015.

Revenue recognition and natural gas imbalances

We use the sales method of accounting for oil and natural gas revenues. We record sales revenue based on an estimate of the volumes delivered at estimated prices as determined by the applicable sales agreement. We estimate our sales volumes primarily on company-measured volume readings. We then adjust our oil and natural gas sales in subsequent periods based on the data received from our purchasers that reflects actual volumes and prices received. Historically, these differences have been immaterial. Gas imbalances at December 31, 2015, 2014 and 2013 were not significant.

Asset retirement obligations

We follow FASB ASC 410-20, *Asset Retirement Obligations (*"ASC 410-20") to account for legal obligations associated with the retirement of long-lived assets. ASC 410-20 requires these obligations be recognized at their estimated fair value at the time that the obligations are incurred. The costs of plugging and abandoning oil and natural gas properties fluctuate with costs associated with the industry. Our calculation of asset retirement obligations uses numerous assumptions and judgments, including the ultimate settlement amounts, inflation factors, credit adjusted discount rates, timing of settlement, and changes in the legal, regulatory, environmental, and political environments. We periodically assess the estimated costs of our asset retirement obligations and adjust the liability according to these estimates.

Income taxes

Income taxes are accounted for in accordance FASB ASC 740, *Income Taxes*. Deferred taxes are recorded to reflect the tax benefits and consequences of future years' differences between the tax basis of assets and liabilities and their financial reporting basis. We must make certain estimates related to the reversal of temporary differences, and actual results could vary from those estimates. We assess, using all available positive and negative evidence, the likelihood that the deferred tax assets will be recovered from future taxable income. Examples of positive and negative evidence include historical taxable income or losses, forecasted income or losses, the estimated timing of the reversals of existing temporary differences as well as prudent and feasible tax planning strategies. We record a valuation allowance to reduce deferred tax assets if it is more likely than not that some portion or all of the deferred tax assets will not be realized. As of December 31, 2015, we continued to have a full valuation allowance against our net deferred tax assets. A significant amount of judgment is also required in determining the amount of unrecognized tax benefit to record for uncertain tax positions. We consider the amounts and probabilities of the outcomes that could be realized upon ultimate settlement of an uncertain tax position using the facts, circumstances and information available at the reporting date to establish the appropriate amount of unrecognized tax benefit. We currently do not have any uncertain tax positions recorded as of December 31, 2015.

Our results of operations

A summary of key financial data for the years ended December 31, 2015, 2014 and 2013 related to our results of operations is presented below:

	Year Ended December 31,			Year to year change	
(dollars in thousands, except per unit prices)	2015	2014	2013	2015-2014	2014-2013
Production:					
Oil (Mbbls)	2,342	2,236	1,188	106	1,048
Natural gas (Mmcf)	109,926	122,324	154,779	(12,398)	(32,455)
Total production (Mmcfe) (1)	123,978	135,740	161,907	(11,762)	(26,167)
Average daily production (Mmcfe)	340	372	444	(32)	(72)
Revenues before derivative financial instrument activities:					
Oil	$ 102,787	$ 196,316	$ 111,440	$ (93,529)	$ 84,876
Natural gas	225,544	463,953	522,869	(238,409)	(58,916)
Total revenues	$ 328,331	$ 660,269	$ 634,309	$ (331,938)	$ 25,960
Oil and natural gas derivative financial instruments:					
Gain (loss) on derivative financial instruments	$ 75,869	$ 87,665	$ (320)	$ (11,796)	$ 87,985
Average sales price (before cash settlements of derivative financial instruments):					
Oil (per Bbl)	$ 43.89	$ 87.80	$ 93.80	$ (43.91)	$ (6.00)
Natural gas (per Mcf)	2.05	3.79	3.38	(1.74)	0.41
Natural gas equivalent (per Mcfe)	2.65	4.86	3.92	(2.21)	0.94
Costs and expenses:					
Oil and natural gas operating costs	$ 53,903	$ 64,467	$ 61,277	$ (10,564)	$ 3,190
Production and ad valorem taxes	22,630	29,859	21,971	(7,229)	7,888
Gathering and transportation	99,321	101,574	100,645	(2,253)	929
Depletion	213,302	258,266	237,899	(44,964)	20,367
Depreciation and amortization	2,124	5,303	7,876	(3,179)	(2,573)
General and administrative (2)	58,818	65,920	91,878	(7,102)	(25,958)
Interest expense, net	106,082	94,284	102,589	11,798	(8,305)
Costs and expenses (per Mcfe):					
Oil and natural gas operating costs	$ 0.43	$ 0.47	$ 0.38	$ (0.04)	$ 0.09
Production and ad valorem taxes	0.18	0.22	0.14	(0.04)	0.08
Gathering and transportation	0.80	0.75	0.62	0.05	0.13
Depletion	1.72	1.90	1.47	(0.18)	0.43
Depreciation and amortization	0.02	0.04	0.05	(0.02)	(0.01)
Net income (loss) (3)	$ (1,192,381)	$ 120,669	$ 22,204	$ (1,313,050)	$ 98,465

(1) Mmcfe is calculated by converting one barrel of oil into six Mcf of natural gas.
(2) Equity-based compensation expense included in general and administrative expenses was $7.2 million, $5.0 million and $10.7 million for the years ended December 31, 2015, 2014 and 2013, respectively.
(3) Net loss for the year ended December 30, 2015 included a $1.2 billion impairment of oil and natural gas properties. See "Note 2. Summary of significant accounting policies" in the Notes to Consolidated Financial Statements for further discussion.

The following is a discussion of our financial condition and results of operations for the years ended December 31, 2015, 2014 and 2013.

The comparability of our results of operations for 2015, 2014 and 2013 was affected by:

- the acquisitions of the Haynesville and Eagle Ford assets during 2013;
- the formation and subsequent sale of Compass during 2013 and 2014, respectively;

- the sale of our equity interest in TGGT during 2013;
- fluctuations in oil and natural gas prices, which impact our oil and natural gas reserves, revenues, cash flows and net income or loss;
- impairments of our oil and natural gas properties in 2015 and 2013;
- asset impairments and other non-recurring costs;
- mark-to-market gains and losses from our derivative financial instruments;
- changes in Proved Reserves and production volumes and their impact on depletion;
- the impact of declining natural gas production volumes from our reduced horizontal drilling activities in certain shale formations;
- significant changes in our capital structure as a result of debt financing transactions in 2015 and 2014 and the rights offering and related private placement of our common shares ("Rights Offering") in 2014;
- gain on restructuring of debt and accounting treatment for the debt exchange transactions during the fourth quarter of 2015; and
- changes in general and administrative expenses as a result of the services and investment agreement with ESAS and the reductions in our workforce that occurred during the second quarter of 2014, first quarter of 2015 and fourth quarter of 2015.

General

The availability of a ready market and the prices for oil and natural gas are dependent upon a number of factors that are beyond our control. These factors include, among other things:

- supply and demand for oil and natural gas and expectations regarding supply and demand;
- the level of domestic and international production;
- the availability of imported oil and natural gas;
- federal regulations applicable to the export of, and construction of export facilities for natural gas;
- political and economic conditions and events in foreign oil and natural gas producing nations, including embargoes, continued hostilities in the Middle East and other sustained military campaigns, and acts of terrorism or sabotage;
- the ability of members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- the cost and availability of transportation and pipeline systems with adequate capacity;
- the cost and availability of other competitive fuels;
- fluctuating and seasonal demand for oil, natural gas and refined products;
- concerns about global warming or other conservation initiatives and the extent of governmental price controls and regulation of production;
- regional price differentials and quality differentials of oil and natural gas;
- the availability of refining capacity;
- technological advances affecting oil and natural gas production and consumption;
- weather conditions and natural disasters;
- foreign and domestic government relations; and
- overall domestic and global economic conditions.

Accordingly, in light of the many uncertainties affecting the supply and demand for oil, natural gas and refined petroleum products, we cannot accurately predict the prices or marketability of oil and natural gas from any producing well in which we have or may acquire an interest.

Marketing arrangements

We produce oil and natural gas. We do not refine or process the oil or natural gas we produce. We sell the majority of the oil we produce under contracts using market sensitive pricing. The majority of our oil contracts are based on NYMEX pricing, which is typically calculated as the average of the daily closing prices of oil to be delivered one month in the future. We also sell a portion of our oil at F.O.B. field prices posted by the principal purchaser of oil where our producing properties are located. Our sales contracts are of a type common within the industry, and we usually negotiate a separate contract for each area. Generally, we sell our oil to purchasers and refiners near the areas of our producing properties.

We sell the majority of our natural gas under individually negotiated gas purchase contracts using market sensitive pricing. Our sales contracts vary in length from spot market sales of a single day to term agreements that may extend for a year or more. Our natural gas customers include utilities, natural gas marketing companies and a variety of commercial and industrial end users. The natural gas purchase contracts define the terms and conditions unique to each of these sales. The price received for natural gas sold on the spot market varies daily, reflecting changing market conditions.

We may be unable to market all of the oil or natural gas we produce. If our oil and natural gas can be marketed, we may be unable to negotiate favorable pricing and contractual terms. Changes in oil or natural gas prices may significantly affect our revenues, cash flows, the value of our oil and natural gas properties and the estimates of recoverable oil and natural gas reserves. Further, significant declines in the prices of oil or natural gas may have a material adverse effect on our business and on our financial condition.

We engage in oil and natural gas production activities in geographic regions where, from time to time, the supply of oil or natural gas available for delivery exceeds the demand. If this occurs, companies purchasing oil or natural gas in these areas may reduce the amount of oil or natural gas that they purchase from us. If we cannot locate other buyers for our production or for any of our oil or natural gas reserves, we may shut in our oil or natural gas wells for certain periods of time. Furthermore, we may shut in our oil and natural gas wells if regional market prices decrease to a level that is uneconomical to produce. If this occurs, we may incur additional payment obligations under our oil and natural gas leases and, under certain circumstances, the oil and natural gas leases might be terminated. Economic conditions, particularly depressed oil and natural gas prices, may negatively impact the liquidity and creditworthiness of our purchasers and may expose us to risk with respect to the ability to collect payments for the oil and natural gas we deliver.

Presentation of results of operations

Our discussion of production, revenues and direct operating expenses is based on our producing regions. For the years ended December 31, 2014 and 2013, our results from Compass are included in Other region in the tables below. The operating results of Compass represent our proportionate interest from its formation on February 14, 2013 to the closing of the sale of our interest on October 31, 2014.

Oil and natural gas production, revenues and prices

The following table presents our production, revenue and average sales prices for the years ended December 31, 2015 and 2014:

	Year Ended December 31,								
	2015			2014			Year to year change		
(dollars in thousands, except per unit rate)	Production (Mmcfe)	Revenue	$/Mcfe	Production (Mmcfe)	Revenue	$/Mcfe	Production (Mmcfe)	Revenue	$/Mcfe
Producing region:									
North Louisiana	73,896	$ 159,685	$ 2.16	82,327	$ 329,736	$ 4.01	(8,431)	$ (170,051)	$ (1.85)
East Texas	18,275	45,656	2.50	10,589	41,338	3.90	7,686	4,318	(1.40)
South Texas	15,220	96,008	6.31	13,713	176,022	12.84	1,507	(80,014)	(6.53)
Appalachia	16,585	26,978	1.63	21,289	67,794	3.18	(4,704)	(40,816)	(1.55)
Other	2	4	2.00	7,822	45,379	5.80	(7,820)	(45,375)	(3.80)
Total	123,978	$ 328,331	$ 2.65	135,740	$ 660,269	$ 4.86	(11,762)	$ (331,938)	$ (2.21)

Production for the year ended December 31, 2015 decreased by 11.8 Bcfe, or 9%, as compared with 2014. Significant components of the changes in production were a result of:

- decreased production of 8.4 Bcfe for the year ended December 31, 2015 in the North Louisiana region primarily due to production declines in excess of additional volumes from recent wells turned-to-sales. We also implemented additional rate restrictions during the flowback of recent wells turned-to-sales in this region, which reduced the initial production but are expected to improve the long-term performance of the wells.
- increased production of 7.7 Bcfe for the year ended December 31, 2015 in the East Texas region due to additional development as we resumed our drilling program in this region during 2014 and this region was the primary focus of our 2015 development program.
- increased production of 1.5 Bcfe for the year ended December 31, 2015 in the South Texas region due to additional volumes from recent wells turned-to-sales in the Eagle Ford shale and Buda formation. We suspended our drilling program in the South Texas region in the fourth quarter of 2015 due to low oil prices.
- decreased production of 4.7 Bcfe for the year ended December 31, 2015 in the Appalachia region as a result of production declines. Production for the year ended December 31, 2015 was impacted by approximately 1.1 Bcfe

shut-in due to low regional natural gas prices and a reduction of volumes of 0.3 Bcfe due to a pipeline disruption in Northeast Pennsylvania.
- decreased production in the Other region primarily due to the sale of our interest in Compass during the fourth quarter of 2014.

Oil and natural gas revenues for the year ended December 31, 2015 decreased by $331.9 million, or 50%, as compared with 2014. The decrease in revenues was primarily the result of a decrease in oil and natural gas prices as well as decreased production consistent with our reduced development program. Our average natural gas sales price decreased 46% to $2.05 per Mcf for the year ended December 31, 2015 from $3.79 per Mcf for the year ended December 31, 2014, primarily due to lower market prices. Our average sales price of oil per Bbl decreased 50% to $43.89 per Bbl for the year ended December 31, 2014 from $87.80 per Bbl for the year ended December 31, 2014, primarily due to lower market prices. The impact of lower market prices was partially offset by improved differentials in the South Texas region due to a renegotiated sales contract which resulted in a higher realized price for the related oil production. Our average sales price for oil in the South Texas region is most closely correlated to the Louisiana Light Sweet ("LLS") price index. During late 2015, the premium of the LLS price index compared to the WTI price index significantly narrowed compared to historical levels.

The following table and discussion presents our production, revenue and average sales prices for the years ended December 31, 2014 and 2013:

	Year Ended December 31,								
	2014			2013			Year to year change		
(dollars in thousands, except per unit rate)	Production (Mmcfe)	Revenue	$/Mcfe	Production (Mmcfe)	Revenue	$/Mcfe	Production (Mmcfe)	Revenue	$/Mcfe
Producing region:									
North Louisiana	82,327	$329,736	$ 4.01	110,373	$374,578	$ 3.39	(28,046)	$ (44,842)	$ 0.62
East Texas	10,589	41,338	3.90	12,845	43,233	3.37	(2,256)	(1,895)	0.53
South Texas	13,713	176,022	12.84	6,197	85,926	13.87	7,516	90,096	(1.03)
Appalachia	21,289	67,794	3.18	22,816	78,424	3.44	(1,527)	(10,630)	(0.26)
Other	7,822	45,379	5.80	9,676	52,148	5.39	(1,854)	(6,769)	0.41
Total	135,740	$660,269	$ 4.86	161,907	$634,309	$ 3.92	(26,167)	$ 25,960	$ 0.94

Production for the year ended December 31, 2014 decreased by 26.2 Bcfe, or 16%, as compared with 2013. Significant components of the changes in production were a result of:

- decreased production in East Texas and North Louisiana regions primarily due to production declines from changes in our drilling program and the initial contribution of properties to Compass in the first quarter of 2013. The production declines were primarily the result of reduced development activities within this region compared to periods prior to 2013.
- increased production in the South Texas region primarily due to more days of production in the current period as the acquisition of these properties occurred on July 31, 2013.
- decreased production of in the Appalachia region due to natural production declines following the suspension of our drilling program during the second half of 2013.
- decreased production in the Other region primarily due to the sale of our interest in Compass on October 31, 2014.

Oil and natural gas revenues for the year ended December 31, 2014 increased by $26.0 million, or 4%, as compared with 2013. The increase in revenues was primarily the result of the acquisition of Haynesville and Eagle Ford assets in the third quarter of 2013 and an increase in natural gas prices. This was partially offset by the decrease in production compared to the prior year. Our average natural gas sales price increased 13% to $3.79 per Mcf for the year ended December 31, 2014 from $3.35 per Mcf for the year ended December 31, 2013. Our average sales price for natural gas during the year ended December 31, 2014 was positively impacted by higher market prices and was partially offset by the widening of differentials in Appalachia as a result of an oversupply of natural gas in the Northeast region. Our average sales price of oil per Bbl decreased 6% to $87.80 per Bbl for the year ended December 31, 2014 from $93.80 per Bbl for the year ended December 31, 2013.

Oil and natural gas operating costs

The following tables and discussion present our oil and natural gas operating costs for the years ended December 31, 2015, 2014, and 2013.

	Year Ended December 31,								
	2015			2014			Year to year change		
(in thousands)	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total
Producing region:									
North Louisiana	$ 13,342	$ 2,798	$ 16,140	$ 14,741	$ 3,539	$ 18,280	$ (1,399)	$ (741)	$ (2,140)
East Texas	4,097	1,426	5,523	3,315	276	3,591	782	1,150	1,932
South Texas......................	18,768	2,007	20,775	15,242	396	15,638	3,526	1,611	5,137
Appalachia	10,806	615	11,421	14,072	58	14,130	(3,266)	557	(2,709)
Other	44	—	44	11,138	1,690	12,828	(11,094)	(1,690)	(12,784)
Total............................	$ 47,057	$ 6,846	$ 53,903	$ 58,508	$ 5,959	$ 64,467	$(11,451)	$ 887	$(10,564)

	Year Ended December 31,								
	2015			2014			Year to year change		
(per Mcfe)	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total	Lease operating expenses	Workovers and other	Total
Producing region:									
North Louisiana	$ 0.18	$ 0.04	$ 0.22	$ 0.18	$ 0.04	$ 0.22	$ —	$ —	$ —
East Texas	0.22	0.08	0.30	0.31	0.03	0.34	(0.09)	0.05	(0.04)
South Texas......................	1.23	0.13	1.36	1.11	0.03	1.14	0.12	0.10	0.22
Appalachia	0.65	0.04	0.69	0.66	—	0.66	(0.01)	0.04	0.03
Other	N/M	—	—	1.42	0.22	1.64	N/M	N/M	N/M
Total............................	$ 0.38	$ 0.05	$ 0.43	$ 0.43	$ 0.04	$ 0.47	$ (0.05)	$ 0.01	$ (0.04)

Oil and natural gas operating costs for the year ended December 31, 2015 decreased by $10.6 million, or 16%, as compared with 2014. The decrease was primarily due to the sale of our interest in Compass in the fourth quarter of 2014 and cost reduction efforts, including significant reductions in force, in the North Louisiana and Appalachia regions. These decreases were partially offset by higher oil and natural gas operating costs in the East Texas and South Texas regions as a result of additional producing wells compared to prior periods. The decrease in oil and natural operating costs per Mcfe was primarily due to the sale of our interest in Compass which had a higher average cost per Mcfe compared to the average for the rest of our properties.

Oil and natural gas operating costs for the year ended December 31, 2015 were $0.43 per Mcfe compared to $0.47 per Mcfe for the year ended December 31, 2014. The decrease in oil and natural operating costs per Mcfe was primarily due to the sale of our interest in Compass, which had a higher average cost per Mcfe compared to the average for the rest of our properties, and cost reduction efforts across our producing regions.

(in thousands)	2014 Lease operating expenses	2014 Workovers and other	2014 Total	2013 Lease operating expenses	2013 Workovers and other	2013 Total	Year to year change Lease operating expenses	Year to year change Workovers and other	Year to year change Total
Producing region:									
North Louisiana	$ 14,741	$ 3,539	$ 18,280	$ 13,171	$ 3,961	$ 17,132	$ 1,570	$ (422)	$ 1,148
East Texas	3,315	276	3,591	3,809	333	4,142	(494)	(57)	(551)
South Texas	15,242	396	15,638	11,454	13	11,467	3,788	383	4,171
Appalachia	14,072	58	14,130	14,073	—	14,073	(1)	58	57
Other	11,138	1,690	12,828	13,020	1,443	14,463	(1,882)	247	(1,635)
Total	$ 58,508	$ 5,959	$ 64,467	$ 55,527	$ 5,750	$ 61,277	$ 2,981	$ 209	$ 3,190

(per Mcfe)	2014 Lease operating expenses	2014 Workovers and other	2014 Total	2013 Lease operating expenses	2013 Workovers and other	2013 Total	Year to year change Lease operating expenses	Year to year change Workovers and other	Year to year change Total
Producing region:									
North Louisiana	$ 0.18	$ 0.04	$ 0.22	$ 0.12	$ 0.04	$ 0.16	$ 0.06	$ —	$ 0.06
East Texas	0.31	0.03	0.34	0.30	0.03	0.33	0.01	—	0.01
South Texas	1.11	0.03	1.14	1.85	—	1.85	(0.74)	0.03	(0.71)
Appalachia	0.66	—	0.66	0.62	—	0.62	0.04	—	0.04
Other	1.42	0.22	1.64	1.35	0.15	1.50	0.07	0.07	0.14
Total	$ 0.43	$ 0.04	$ 0.47	$ 0.34	$ 0.04	$ 0.38	$ 0.09	$ —	$ 0.09

Oil and natural gas operating costs for the year ended December 31, 2014 increased by $3.2 million, or 5%, as compared with 2013. The increase in oil and natural gas operating costs was primarily due to the acquisition of the Eagle Ford assets. This was partially offset by the lower operating costs resulting from the contribution of properties to Compass in the first quarter of 2013 as well as the sale of our interest in Compass on October 31, 2014. We implemented several costs reduction initiatives in the South Texas region in 2014 which resulted in decreased saltwater disposal costs, improved efficiencies and reduced reliance on third-party contractors.

Oil and natural gas operating costs for the year ended December 31, 2014 were $0.47 per Mcfe compared to $0.38 per Mcfe for the year ended December 31, 2013. The net increase in oil and natural gas operating costs per Mcfe is primarily attributable to lower production in relation to certain fixed lease operating expenses. This increase was partially offset by the cost reduction initiatives in the South Texas region, as well as the contribution and the sale of properties to Compass in 2013 and 2014, respectively, which typically have a higher average cost per Mcfe compared to the average for the rest of our properties. As a result of the cost reduction initiatives in the South Texas region, we were able to reduce our costs per Mcfe in the region to $1.14 per Mcfe in 2014 from $1.85 per Mcfe in 2013.

Gathering and transportation

Gathering and transportation expenses for the year ended December 31, 2015 decreased by $2.3 million, or 2%, as compared with 2014. The decrease was primarily due to reduced rates on a renegotiated firm transportation contract in the North Louisiana region, sale of our interest in Compass and decreased production in Appalachia. These decreases were partially offset by additional expenses incurred as a result of a shortfall under a minimum volume commitment for gathering services in the East Texas and North Louisiana regions. Gathering and transportation expenses were $0.80 per Mcfe for the year ended December 31, 2015, as compared to $0.75 per Mcfe for the year ended December 31, 2014. The increase was primarily due to lower volumes in relation to fixed costs under firm transportation contracts in the North Louisiana region. As a result of our planned reduction in development and related lower production volumes for 2016, our gathering and transportation cost per Mcfe is expected to increase due to the nature of the fixed costs associated with gathering and firm transportation contracts.

Gathering and transportation expenses for the year ended December 31, 2014 increased by $0.9 million, or 1%, as compared with 2013. Gathering and transportation expenses were $0.75 per Mcfe for the year ended December 31, 2014, as compared to $0.62 per Mcfe for the year ended December 31, 2013. The increase in gathering and transportation expenses on a per Mcfe basis was primarily due to lower volumes in relation to fixed costs under firm transportation contracts in the North

Louisiana region. In addition, a marketing arrangement with a significant purchaser of our Haynesville shale production volumes was amended in April 2014 resulting in higher gathering and transportation expenses.

Production and ad valorem taxes

	Year Ended December 31,								
	2015			2014			2013		
(in thousands, except per unit rate)	Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe	Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe	Production and ad valorem taxes	% of revenue	Taxes $/ Mcfe
Producing region:									
North Louisiana	$ 10,027	6.3%	$ 0.14	$ 9,581	2.9%	$ 0.12	$ 8,323	2.2%	$ 0.08
East Texas	1,059	2.3%	0.06	451	1.1%	0.04	964	2.2%	0.08
South Texas	10,216	10.6%	0.67	13,406	7.6%	0.98	4,962	5.8%	0.80
Appalachia	1,336	5.0%	0.08	2,256	3.3%	0.11	2,653	3.4%	0.12
Other	(8)	N/M	N/M	4,165	9.2%	0.53	5,069	9.7%	0.52
Total	$ 22,630	6.9%	$ 0.18	$ 29,859	4.5%	$ 0.22	$ 21,971	3.5%	$ 0.14

Production and ad valorem taxes for the year ended December 31, 2015 decreased by $7.2 million, or 24%, as compared to 2014. The decrease was primarily due to lower production volumes and lower commodity prices. The lower commodity prices primarily impacted properties located in Texas because production taxes are based on a fixed percentage of gross value of production sold. Production and ad valorem taxes for the year ended December 31, 2014 increased by $7.9 million, or 36%, as compared to 2013. The increase was primarily attributable to higher production and ad valorem taxes associated with oil production in the South Texas region. Additionally, this increase was due to higher severance tax rates in the State of Louisiana and the expiration of severance tax holidays on certain Haynesville shale wells in the North Louisiana region.

Production and ad valorem tax rates per Mcfe were $0.18, $0.22 and $0.14 for 2015, 2014 and 2013, respectively. The rate per Mcfe decreased from 2014 to 2015 due to the sale of our interest in Compass in the fourth quarter of 2014 which had higher average production and ad valorem taxes per Mcfe compared to the average for the rest of our properties. Also, the recent wells turned-to-sales in the East Texas region received severance tax exemptions which reduced the rate per Mcfe. The rate per Mcfe increased from 2013 to 2014 due to higher production and ad valorem taxes per Mcfe associated with oil production in the South Texas region, higher severance tax rates in the State of Louisiana and the expiration of severance tax holidays on certain Haynesville shale wells in the North Louisiana region.

In our North Louisiana region, we currently receive severance tax holidays on certain horizontal wells which reduce the effective rate of these taxes. Our horizontal wells in the state of Louisiana are eligible for an exemption from severance taxes for the earlier of two years from the date of first production or until payout of qualified costs. In July 2014, the state of Louisiana increased its severance tax rate for wells that do not receive exemptions from $0.118 per Mcf to $0.163 per Mcf. In July 2015, the effective severance tax rate decreased to $0.158 per Mcf.

Production and ad valorem taxes are set by state and local governments and vary as to the tax rate and the value to which that rate is applied. In Louisiana, where a substantial percentage of our production is derived, severance taxes are levied on a per Mcf basis. Therefore, the resulting dollar value of production is not sensitive to changes in prices for natural gas, except for holiday exemptions, if any. In our other operating areas, particularly Texas, production taxes are based on a fixed percentage of gross value of production sold. As such, our realized severance and ad valorem tax rates may become more sensitive to prices, except for wells that receive holiday exemptions, if any. The Commonwealth of Pennsylvania requires an impact fee to be paid on all unconventional wells spud based on a price tier calculation for a period of 15 years. Multiple pieces of legislation have been introduced in both the Pennsylvania House and the Senate that propose a severance tax at varying rates on the production of oil and natural gas. This severance tax would likely be in addition to the impact fee and could have an impact on our production taxes in future periods. There is no certainty that this legislation will be passed nor is it possible to quantify the impact at this time.

Depletion, depreciation and amortization

Depletion expense for the year ended December 31, 2015 decreased by $45.0 million, or 17%, as compared with 2014 primarily due to a decrease in production and the depletion rate. On a per Mcfe basis, the depletion rate for the year ended

December 31, 2015 was $1.72 per Mcfe, compared with $1.90 per Mcfe in 2014. The decrease in the depletion rate was primarily due to the impairments of our oil and natural gas properties during 2015, which lowered our depletable base. Our depletion rate decreased each quarter during 2015 and is expected to continue to decrease in the future due to reductions in our depletable base resulting from impairments to our oil and natural gas properties. Depletion expense for the year ended December 31, 2014 increased by $20.4 million, or 9%, as compared with 2013 primarily due to the acquisition of assets in the Haynesville and Eagle Ford shale during the third quarter of 2013. On a per Mcfe basis, the depletion rate for the year ended December 31, 2014 was $1.90 per Mcfe, compared with $1.47 per Mcfe in 2013. The increase in the depletion rate was primarily due to the acquisition of assets in the Haynesville and Eagle Ford shale during the third quarter of 2013 which increased our depletable base and higher future development costs associated with the additional proved undeveloped reserves. The oil producing assets in the Eagle Ford shale result in a higher depletion rate when calculated on per Mcfe basis compared to the rest of our properties.

Depreciation and amortization costs for the year ended December 31, 2015 decreased by $3.2 million, or 60%, as compared with the same period in 2014. The decrease was primarily due to lower depreciable assets as a result of the sale of our interest in Compass. Depreciation and amortization costs for the year ended December 31, 2014 decreased by $2.6 million, or 33%, as compared with the same period in 2013. The decrease was due to the contribution of gathering assets to Compass in the first quarter of 2013 and reduced spending on certain corporate assets.

Impairment of oil and natural gas properties

For the year ended December 31, 2015, we recorded impairments to our oil and natural gas properties of $1.2 billion primarily due to the significant decline in oil and natural gas prices partially offset by upward revisions in the oil and natural gas reserves primarily as a result of performance and other factors. The trailing twelve month reference prices at December 31, 2015 were $2.59 per Mmbtu for natural gas and $50.28 per Bbl of oil. For the year ended December 31, 2014 we did not record impairments to our oil and natural gas properties and we recorded impairments of $108.5 million to our oil and natural gas properties for the year ended December 31, 2013. We may incur additional impairments to our oil and natural gas properties in 2016 if oil and natural gas prices do not increase. The possibility and amount of any future impairment is difficult to predict, and will depend, in part, upon future oil and natural gas prices to be utilized in the ceiling test, estimates of proved reserves and future capital expenditures and operating costs.

If the simple average of oil and natural gas prices as of the first day of each month for the trailing 12-month period ended December 31, 2015 had been $2.45 per Mmbtu for natural gas and $46.03 per Bbl of oil while all other factors remained constant, our ceiling test limitation related to the net book value of our proved oil and natural gas properties would have been reduced by approximately $101 million. The aforementioned prices were calculated based on a 12-month simple average, which includes the oil and natural gas prices on the first day of the month for the 11 months ended February 2015 and the prices for February 2015 were held constant for the remaining month. This reduction would have increased the impairment of our oil and natural gas properties pursuant to the ceiling test by approximately $101 million on a pro forma basis as of December 31, 2015. The pro forma reduction in our ceiling test limitation is partially the result of a pro forma decrease in our proved undeveloped reserves of approximately 19%, which was primarily due to certain locations that would not be economical when using the pro forma prices. This calculation of the impact of lower commodity prices is prepared based on the presumption that all other inputs and assumptions are held constant with the exception of oil and natural gas prices. Therefore, this calculation strictly isolates the impact of commodity prices on our ceiling test limitation and proved reserves. The impact of price is only a single variable in the estimation of our proved reserves and other factors could have a significant impact on future reserves and the present value of future cash flows. The other factors that impact future estimates of proved reserves include, but are not limited to, extensions and discoveries, changes in costs, drilling results, revisions due to performance and other factors, changes in development plans and production. There are numerous uncertainties inherent in the estimation of proved reserves and accounting for oil and natural gas properties in subsequent periods and this pro forma estimate should not be construed as indicative of our development plans or future results.

General and administrative

The following table presents our general and administrative expenses for the years ended December 31, 2015, 2014 and 2013:

(in thousands, except per unit rate)	Year Ended December 31, 2015	2014	2013	Year to year change 2015-2014	2014-2013
General and administrative costs:					
Gross general and administrative expense	$ 87,788	$ 109,499	$ 129,396	$ (21,711)	$ (19,897)
Technical services and service agreement charges	(15,884)	(24,747)	(26,846)	8,863	2,099
Operator overhead reimbursements	(13,126)	(13,507)	(10,462)	381	(3,045)
Capitalized salaries	(7,158)	(10,287)	(10,958)	3,129	671
General and administrative expense, excluding equity-based compensation	51,620	60,958	81,130	(9,338)	(20,172)
Gross equity-based compensation	10,626	10,460	18,036	166	(7,576)
Capitalized equity-based compensation	(3,428)	(5,498)	(7,288)	2,070	1,790
General and administrative expense	$ 58,818	$ 65,920	$ 91,878	$ (7,102)	$ (25,958)

General and administrative expenses for the year ended December 31, 2015 decreased by $7.1 million, or 11%, compared with 2014. Significant components of the changes in general and administrative expense for the year ended December 31, 2015 compared to 2014 were a result of:

- decreased personnel costs of $17.5 million for the year ended December 31, 2015 compared to the same period in the prior year. The decrease is primarily the result of reductions in our workforce that occurred during the second quarter of 2014 and the first and fourth quarters of 2015. These decreases were offset by higher severance costs paid in 2015 of $5.3 million as compared to $2.2 million in 2014. Personnel costs are expected to continue to decrease in 2016 as we realize a full year of cost savings from the reduction in force and other initiatives such as the elimination of the employer matching program on our 401(k) plan and other benefits;
- increased consulting and contract labor costs of $3.2 million for the year ended December 31, 2015 compared to the same period in the prior year. The increase primarily related to service fees to ESAS totaling $2.7 million and the accrual of the annual incentive payment to ESAS of $1.8 million as a result of EXCO's performance rank during 2015. This was partially offset by less reliance on consulting and contract labor as part of our cost reduction initiatives;
- decreased various other gross general and administrative expenses of $7.4 million for the year ended December 31, 2015 compared to the same period in the prior year. These decreases reflect our efforts to reduce our general and administrative costs such as office expenses, professional fees, travel and software licenses;
- decreased technical services and service agreement recoveries of $8.9 million for the year ended December 31, 2015 compared to the same period in the prior year. These decreases were primarily a result of reduced headcount and lower recoveries in connection with the transition service agreement with Compass that terminated in April 2015;
- decreased capitalized salaries of $3.1 million and capitalized equity-based compensation of $2.1 million for the year ended December 31, 2015 compared to the same period in the prior year. These decreases were primarily as a result of a reduction in employee headcount; and
- increased equity-based compensation of $0.2 million for the year ended December 31, 2015 compared to the same period in the prior year. The increase was primarily due to $3.2 million of additional compensation expense related to the warrants issued to ESAS in 2015. This was offset by lower equity-based compensation to employees as a result of the reductions in our workforce.

General and administrative expenses for the year ended December 31, 2014 decreased by $26.0 million, or 28%, compared with 2013. Significant components of the changes in general and administrative expense for the year ended December 31, 2014 compared to 2013 were a result of:

- decreased personnel and employee relocation costs of $12.4 million. The decrease was primarily the result of a reduction in our workforce and the centralization of certain functions from the Appalachia region. Also, we incurred $5.0 million of severance costs during 2013 associated with the resignation of our former chairman and chief executive officer. The decrease was partially offset by $2.2 million in severance costs associated with the reduction in our workforce during the second quarter of 2014;
- decreased gross equity-based compensation expense of $7.6 million. The decrease was primarily due to a reduction in headcount, higher forfeitures and additional expenses incurred with the modification of equity-based payments in connection with the retirement and resignation of former executives in the prior year;

- decreased various other gross general and administrative expenses of $7.5 million. The decrease reflects our efforts to reduce our general and administrative costs such as office expenses, travel and software licenses. We also incurred additional costs for legal and transition services related to the Haynesville and Eagle Ford asset acquisitions in 2013;
- decreased technical services and service agreement recoveries of $2.1 million. The decrease was primarily a result of reduced headcount and increased focus on the development of assets that are not included in joint venture arrangements in which we can recover technical services including our operations in the South Texas region;
- increased operator overhead reimbursements of $3.0 million. The increase is primarily associated with the additional operated wells acquired and developed in the Haynesville and Eagle Ford shales; and
- decreased capitalized salaries and capitalized equity-based compensation of $2.5 million primarily as a result of a reduction in employee headcount.

(Gain) loss on divestitures and other operating items

(Gain) loss on divestitures and other operating items were net losses of $0.5 million and $5.3 million and a net gain of $177.5 million for the years ended December 31, 2015, 2014 and 2013, respectively. The net loss for the year ended December 31, 2015 primarily consisted of legal expenses and other assessments partially offset by income from surface acreage that we own in the South Texas region. The net loss for the year ended December 31, 2014 primarily consisted of legal expenses. The net gain for the year ended December 31, 2013 was primarily related to the gain of $186.4 million as a result of the contribution of certain oil and natural gas properties to Compass. Partially offsetting the gain were transaction costs associated with the acquisition of Haynesville and Eagle Ford assets and legal expenses.

Interest expense, net

The following table presents our interest expense for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,			Period to period change	
(in thousands)	**2015**	**2014**	**2013**	**2015-2014**	**2014-2013**
Interest expense, net:					
2018 Notes	$ 50,381	$ 57,585	$ 57,485	$ (7,204)	$ 100
2022 Notes	38,338	30,104	—	8,234	30,104
EXCO Resources Credit Agreement	6,747	16,368	33,119	(9,621)	(16,751)
Fairfax Term Loan	6,764	—	—	6,764	—
Compass Production Partners Credit Agreement	—	2,022	2,335	(2,022)	(313)
Amortization of deferred financing costs	15,729	7,939	28,169	7,790	(20,230)
Capitalized interest	(12,040)	(20,060)	(18,729)	8,020	(1,331)
Other	163	326	210	(163)	116
Total interest expense, net	$ 106,082	$ 94,284	$ 102,589	$ 11,798	$ (8,305)

Interest expense, net for the year ended December 31, 2015 increased $11.8 million from the same period in 2014. Significant components of the changes in interest expense, net for the year ended December 31, 2015 compared to 2014 were a result of:

- decreased interest expense on the 2018 Notes due to a lower outstanding balance resulting from debt restructuring and note repurchases in the fourth quarter of 2015;
- increased interest expense on the 2022 Notes as a result of the 2022 Notes only accruing a partial year's worth of interest in 2014. This was partially offset by the reduction in the outstanding balance as a result of our recent debt restructuring activities in the fourth quarter of 2015;
- decreased interest expense related to the EXCO Resources Credit Agreement due to a lower average outstanding balance in 2015 as compared to 2014 and due to the acceleration of the unamortized discount on the term loan under the EXCO Resources Credit Agreement upon repayment in April 2014;
- additional interest from the Fairfax Term Loan which closed in the fourth quarter of 2015;
- decreased interest expense related to the Compass Production Partners Credit Agreement as a result of the sale of our remaining interest in Compass in the fourth quarter of 2014;
- increased amortization of deferred financing costs primarily due to the acceleration of deferred financing costs of $8.7 million associated with the reductions in our borrowing base under the EXCO Resources Credit Agreement throughout 2015; and
- decreased capitalized interest primarily related to lower balances of unproved oil and natural gas properties.

As discussed in more detail in "Note 5. Debt" in the Notes to our Consolidated Financial Statements, in the fourth quarter of 2015, we closed the Exchange Term Loan and used the proceeds to repurchase a portion of the outstanding 2018 Notes and 2022 Notes in exchange for the holders of such notes agreeing to act as lenders in connection with the Exchange Term Loan. The exchange was accounted for as a troubled debt restructuring pursuant to FASB ASC 470-60, *Troubled Debt Restructuring by Debtors*. As such, all cash payments under the terms of the Exchange Term Loan, whether designated as interest or as principal amount, will reduce the carrying amount and no interest expense, in accordance with GAAP, will be recognized. This will result in a significantly lower interest expense than the contractual interest payments throughout the term of the Exchange Term Loan.

Our interest expense, net for the year ended December 31, 2014 decreased $8.3 million from 2013 primarily due to a decrease in the amortization of deferred financing costs and lower average outstanding indebtedness. We incurred $21.0 million in expense related to accelerated deferred financing costs during 2013 primarily as a result of amendments to the EXCO Resources Credit Agreement. This was partially offset by higher average interest rates during 2014 as a result of the issuance of the 2022 Notes.

Gain (loss) on derivative financial instruments

Our oil and natural gas derivative financial instruments resulted in a net gain of $75.9 million, a net gain of $87.7 million and a net loss of $0.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. The net gains during 2015 were primarily the result of declines in the futures prices of oil and natural gas. Based on the nature of our derivative contracts, decreases in the related commodity price typically result in increases to the value of our derivatives contracts. The significant fluctuations demonstrate the high volatility in oil and natural gas prices between each of the periods. The ultimate settlement amount of the unrealized portion of the derivative financial instruments is dependent on future commodity prices.

The following table presents our natural gas prices, before and after the impact of the cash settlement of our derivative financial instruments.

	Year Ended December 31,			Period to period change	
Average realized pricing:	**2015**	**2014**	**2013**	**2015-2014**	**2014-2013**
Natural gas (per Mcf):					
Net price, excluding derivatives	$ 2.05	$ 3.79	$ 3.38	$ (1.74)	$ 0.41
Cash receipts (payments) on derivatives	0.74	(0.18)	0.26	0.92	(0.44)
Net price, including derivatives	$ 2.79	$ 3.61	$ 3.64	$ (0.82)	$ (0.03)
Oil (per Bbl):					
Net price, excluding derivatives	$ 43.89	$ 87.80	$ 93.80	$ (43.91)	$ (6.00)
Cash receipts (payments) on derivatives	20.12	1.09	2.05	19.03	(0.96)
Net price, including derivatives	$ 64.01	$ 88.89	$ 95.85	$ (24.88)	$ (6.96)
Natural gas equivalent (per Mcfe):					
Net price, excluding derivatives	$ 2.65	$ 4.86	$ 3.92	$ (2.21)	$ 0.94
Cash receipts (payments) on derivatives	1.04	(0.14)	0.26	1.18	(0.40)
Net price, including derivatives	$ 3.69	$ 4.72	$ 4.18	$ (1.03)	$ 0.54

Our total cash settlements for 2015 were receipts of $128.8 million, or $1.04 per Mcfe, compared to payments of $19.0 million, or $0.14 per Mcfe, in 2014 and cash receipts of $42.1 million, or $0.26 per Mcfe, in 2013. As noted above, the significant fluctuations between settlements on our derivative financial instruments demonstrate the volatility in commodity prices. We will continue to evaluate plans to enter into additional derivative contracts based on market conditions.

Gain on restructuring and extinguishment of debt

For the year ended December 31, 2015 we recorded a net gain of $193.3 million in connection with our recent debt restructuring activities. We repurchased a portion of the outstanding 2018 Notes and 2022 Notes in exchange for the holders of such notes agreeing to act as lenders in connection with the Exchange Term Loan which resulted in a net gain of $165.1 million. Additionally, in the fourth quarter of 2015, we repurchased $40.8 million in principal of the 2018 Notes through open market purchases with $12.0 million in cash resulting in a $28.2 million net gain on extinguishment of debt. See "Note 5. Debt" to our Notes to Consolidated Financial Statements for additional information and accounting treatment of these transactions.

Equity income (loss)

Our equity income (loss) was a net loss of $15.7 million, net income of $0.2 million and net loss of $53.3 million for the years ended December 31, 2015, 2014 and 2013, respectively. The decrease in our equity income (loss) for the year ended December 31, 2015 compared with 2014 was primarily due to other than temporary impairments of our midstream investments in the Appalachia region and the East Texas and North Louisiana regions which resulted in a $13.9 million net loss. The impairments were recorded to reduce the carrying values to the fair values.

The increase in equity income for the year ended December 31, 2014 compared with 2013 was primarily due to an impairment of our investment in TGGT during 2013. This was partially offset by equity income from our investment in TGGT prior to the sale of our interest on November 15, 2013.

Income taxes

The following table presents a reconciliation of our income tax provision (benefit) for the years ended December 31, 2015, 2014 and 2013:

(in thousands)	Year Ended December 31, 2015	2014	2013
Federal income taxes (benefit) provision at statutory rate of 35%	$ (417,333)	$ 42,234	$ 7,772
Increases (reductions) resulting from:			
Goodwill	—	—	16,382
Adjustments to the valuation allowance	459,843	(64,757)	(28,865)
Non-deductible compensation	2,399	3,409	1,328
State taxes net of federal benefit	(45,009)	3,464	3,239
State tax rate change	—	15,496	—
Other	100	154	144
Total income tax provision	$ —	$ —	$ —

During all years presented, both federal and state income taxes were reduced to zero by a corresponding increase or decrease to the valuation allowance previously recognized against net deferred tax assets. The net result was no income tax provision for all years presented.

As of December 31, 2015, 2014, and 2013, there were no unrecognized tax benefits, including interest and penalties, that would be required to be recognized in our financial statements.

Our liquidity, capital resources and capital commitments

Overview

Our primary sources of capital resources and liquidity are internally generated cash flows from operations, borrowing capacity under the EXCO Resources Credit Agreement, dispositions of non-strategic assets, joint ventures and capital markets when conditions are favorable. Factors that could impact our liquidity, capital resources and capital commitments include the following:

- the level of planned drilling activities;
- the results of our ongoing drilling programs;

- our ability to fund, finance or repay financing incurred in connection with acquisitions of oil and natural gas properties;
- the integration of acquisitions of oil and natural gas properties or other assets;
- our ability to effectively manage operating, general and administrative expenses and capital expenditure programs;
- reduced oil and natural gas revenues resulting from, among other things, depressed oil and natural gas prices and lower production from reductions to our drilling and development activities;
- our ability to mitigate commodity price volatility with derivative financial instruments;
- our ability to meet minimum volume commitments under firm transportation agreements and other fixed commitments;
- potential acquisitions and/or dispositions of oil and natural gas properties or other assets;
- the potential outcome of litigation related to the claim that we breached our obligation under a participation agreement with a joint venture partner in the Eagle Ford shale;
- limitations on our ability to incur certain types of indebtedness in accordance with our debt agreements;
- our ability to pay interest on our outstanding indebtedness, including the quarterly payments related to the issuance of the Second Lien Term Loans;
- reductions to our borrowing base;
- requirements to provide certain vendors and other parties with letters of credit as a result of our credit quality, which reduce the amount of available borrowings under the EXCO Resources Credit Agreement;
- additional debt restructuring activities including the repurchase of indebtedness or issuance of equity in exchange for indebtedness; and
- our ability to maintain compliance with debt covenants.

Recent events affecting liquidity

EXCO completed a series of debt restructuring transactions during 2015 that were focused on improving our liquidity and reducing indebtedness. On October 26, 2015, we closed the Fairfax Term Loan with an aggregate principal amount of $300.0 million and utilized the proceeds to reduce indebtedness under the EXCO Resources Credit Agreement. We closed the Exchange Term Loan with certain unsecured noteholders in the aggregate principal amount of $291.3 million on October 26, 2015 and $108.7 million on November 4, 2015 and utilized the proceeds to repurchase an aggregate $551.2 million of the outstanding 2018 Notes and $277.2 million of the outstanding 2022 Notes in exchange for the holders of such notes agreeing to act as lenders in connection with the Exchange Term Loan. The Second Lien Term Loans are due in October 2020 and accrue interest at a rate of 12.5% per annum.

In connection with the issuance of the Second Lien Terms loans, the borrowing base under the EXCO Resources Credit Agreement was reduced to $375.0 million. The next scheduled borrowing base redetermination for the EXCO Resources Credit Agreement is set to occur in March 2016. Additionally, we repurchased $40.8 million in principal of the 2018 Notes through open market purchases in the fourth quarter of 2015 with $12.0 million in cash. As a result of these debt restructuring transactions and our operations during 2015, we were able to reduce our total outstanding principal on indebtedness by $304.2 million from December 31, 2014, and our unused borrowing base plus cash was $334.4 million as of December 31, 2015. We have borrowed an additional $28.0 million under the EXCO Resources Credit Agreement subsequent to December 31, 2015 to fund our operations and financing activities such as the repurchase of existing indebtedness at a significant discount to face value.

Our 2016 capital budget is expected to exceed our cash flows from operations and we expect that the deficit will be funded with borrowings under the EXCO Resources Credit Agreement. We continue to evaluate and implement further cost reduction initiatives to mitigate the impact of low commodity prices on our cash flows and liquidity. The initiatives implemented during 2015 have included reductions in our workforce, reduced operating and capital expenditures through negotiations with key vendors and restructuring of commercial contracts including sales and firm transportation agreements. We are currently evaluating transactions that could further enhance our liquidity and capital structure including the issuance of additional indebtedness, the restructuring or repurchase of existing indebtedness, issuance of equity, cost reductions, divestitures of assets or similar transactions. We currently have approximately $125 million of additional liens capacity. Our Board of Directors has authorized the use of up to $35.0 million for repurchases of 2018 Notes and 2022 Notes through open market purchases in addition to the $12.0 million that has been spent to repurchase the 2018 Notes as of December 31, 2015. Since December 31, 2015, we have purchased an additional $9.5 million of 2018 Notes with $2.2 million in cash and $39.9 million of 2022 Notes with $4.5 million in cash. The 2018 Notes and 2022 Notes repurchased will be canceled by the trustee following customary settlement procedures. We have also taken preliminary actions to assess the potential market and valuation if we were to divest certain of our assets. There is no assurance that such transactions will occur.

While we believe that our capital resources from existing cash balances, anticipated cash flow from operating activities and available borrowing capacity under the EXCO Resources Credit Agreement will be adequate to execute our corporate strategies and to meet debt service obligations through 2016 and into 2017, there are certain risks and uncertainties that could negatively impact our results of operations and financial condition. Accordingly, our ability to effectively execute our corporate strategies and manage our operating, general and administrative expenses and capital expenditure programs is critical to our financial condition, liquidity and our results of operations.

The following table presents information relating to the changes in our liquidity and outstanding debt for the year ended December 31, 2015:

(in thousands)	December 31, 2014	Repayments/ repurchases	Borrowings	Exchanges	December 31, 2015
EXCO Resources Credit Agreement	$ 202,492	$ (300,000)	$ 165,000	$ —	$ 67,492
Exchange Term Loan (1)	—	—	—	400,000	400,000
Fairfax Term Loan	—	—	300,000	—	300,000
2018 Notes (2)	750,000	(40,806)	—	(551,179)	158,015
2022 Notes	500,000	—	—	(277,174)	222,826
Total debt (3)	$ 1,452,492	$ (340,806)	$ 465,000	$ (428,353)	$ 1,148,333
Net debt	$ 1,382,217				$ 1,114,866
Borrowing base	$ 900,000				$ 375,000
Unused borrowing base (4)	$ 690,935				$ 300,910
Cash (5)	$ 70,275				$ 33,467
Unused borrowing base plus cash	$ 761,210				$ 334,377

(1) Amount presented is the outstanding principal balance and excludes $241.2 million of deferred reductions to carrying value. See "Note 5. Debt" in the Notes to our Consolidated Financial Statements for additional information.
(2) Excludes unamortized discount of $0.9 million at December 31, 2015.
(3) Excludes unamortized deferred financing costs of $18.3 million at December 31, 2015.
(4) Net of $6.6 million in letters of credit as of December 31, 2015.
(5) Includes restricted cash of $21.2 million at December 31, 2015.

Credit agreements and long-term debt

As of December 31, 2015, our consolidated debt consisted of the EXCO Resources Credit Agreement, 2018 Notes, 2022 Notes and the Second Lien Term Loans (see "Note 5. Debt" in the Notes to our Consolidated Financial Statements for a further description of each agreement).

As of December 31, 2015, we were in compliance with the following financial covenants (each as defined in the EXCO Resources Credit Agreement):

- our consolidated current ratio of 2.7 to 1.0 exceeded the minimum of at least 1.0 to 1.0 as of the end of any fiscal quarter;
- our Interest Coverage Ratio of 2.4 to 1.0 exceeded the minimum of at least 1.25 to 1.0 as of the end of any fiscal quarter. The consolidated interest expense utilized in the Interest Coverage Ratio is calculated in accordance with GAAP; therefore, this excludes cash payments under the terms of the Exchange Term Loan, whether designated as interest or as face amount, that reduce the carrying amount and are not recognized as interest expense. See further details on the accounting for the Exchange Term Loan as described in "Note 5. Debt" in the Notes to our Consolidated Financial Statements; and
- our Senior Secured Indebtedness Ratio of 0.3 to 1.0 did not exceed the maximum of 2.5 to 1.0 as of the end of any fiscal quarter. Senior secured indebtedness utilized in the Senior Secured Indebtedness Ratio excludes the Second Lien Term Loans and any other indebtedness subordinated to the EXCO Resources Credit Agreement.

The issuance of the Second Lien Term Loans triggered a modification of certain covenants in the EXCO Resources Credit Agreement, including the elimination of the leverage ratio requirement. The Second Lien Term Loans and the indentures governing the 2018 Notes and 2022 Notes contain incurrence covenants which restrict our ability to incur additional indebtedness, incur liens to secure any such additional indebtedness or pledge assets. These incurrence covenants include limitations on our indebtedness that are based, in part, on the greater of a monetary threshold or a calculation based on the value of our assets. Our ability to incur additional indebtedness could be limited to the extent that low oil and natural gas prices negatively impact the value of our assets. See further details on the limitations on our ability to incur additional indebtedness as described in "Note 5. Debt" in the Notes to our Consolidated Financial Statements.

There are certain risks arising from volatility in oil and/or natural gas prices that could restrict our liquidity or impact our ability to meet debt covenants in future periods. Furthermore, our liquidity and ability to meet debt covenants in future periods is partially dependent on our ability to offset natural production declines through the development of our oil and natural gas properties. If we are not able to generate sufficient returns from the future development of our oil and natural gas properties, we may not undertake these projects and be able to adequately offset our natural production declines. The profitability of our future development projects is dependent on commodity prices, estimates of reserves, drilling and completion costs, operating costs, and other factors.

Significant reductions in our borrowing capacity as a result of a redetermination of our borrowing base under the EXCO Resources Credit Agreement could have an impact on our capital resources and liquidity. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices. The lenders party to the EXCO Resources Credit Agreement have considerable discretion in setting our borrowing base, and we are unable to predict the outcome of the March 2016 redetermination or any future redeterminations. Any reduction in our borrowing base could result in our liquidity being limited to our cash flow from operations, which is currently in decline as a result of the depressed commodity price environment. If our borrowing base is materially reduced or we are no longer able to draw on the EXCO Resources Credit Agreement or generate sufficient cash flow from operations, we may not be able to fund our operations and drilling activities or pay the interest on our debt, which would result in us defaulting under our various debt instruments and may force us to seek bankruptcy protection or pursue other restructuring alternatives. Our ability to maintain compliance with debt covenants is negatively impacted when oil and/or natural gas prices and/or production declines over an extended period of time. In particular, our Interest Coverage Ratio and Senior Secured Indebtedness Ratio, each as defined in the EXCO Resources Credit Agreement, are computed using EBITDAX for a trailing period which is expected to decrease in 2016 as a result of continued depressed commodity prices. See further details on the accounting for the Exchange Term Loan in "Note 5. Debt" in the Notes to our Consolidated Financial Statements.

In the event that our liquidity is not sufficient to fund our operating activities and development program or we are not able to meet our debt covenants in future periods, we may attempt to refinance all or part of our existing debt, sell assets, incur additional indebtedness or raise equity. These alternatives may not be available on terms acceptable to us, which could adversely affect our business, financial condition and results of operations. Further, failing to comply with the financial and other restrictive covenants in the EXCO Resources Credit Agreement, Second Lien Term Loans, 2018 Notes or 2022 Notes could result in an event of default, which could adversely affect our business, financial condition and results of operations. Also, we may be required to surrender certain assets pursuant to the security provisions of the EXCO Resources Credit Agreement and Second Lien Term Loans if we are not able to meet our debt covenants in future periods. See "Note 5. Debt" in the Notes to our Condensed Consolidated Financial Statements for a description of our covenants under the EXCO Resources Credit Agreement, Second Lien Term Loans, 2018 Notes and 2022 Notes.

Capital commitments

We have a Participation Agreement with a joint venture partner for the development of certain assets in the Eagle Ford shale. EXCO is required to offer to purchase our joint venture partner's working interest in wells drilled that have been on production for at least one year. These offers are required to be made on a quarterly basis for groups of wells based on a price defined in the Participation Agreement, subject to specific well criteria and return hurdles. The wells included in the offer process that meet all of the specific well criteria are deemed to be "Committed Wells" and wells that do not meet the criteria are deemed to be "Uncertainty Wells." The specific well criteria includes factors such as the amount of time on artificial lift, temporary shut-in time, interference from other wells, recent offset fracturing activities or other trends that may result in variability in the performance trends used to establish estimates of reserves. If a group of Committed Wells does not meet the established return thresholds, our joint venture partner has the right to decline our offer and the wells can be included in future offers. Our joint venture partner may accept the offers for the Uncertainty Wells; however, they have the ability to elect to defer those wells to future periods when they meet all of the criteria. Any well included in the offer process that remains an Uncertainty Well for two consecutive quarters becomes a Committed Well in the next quarterly offer process. Our joint venture partner has a right to retain an undivided 15% of their collective interest in the wells that we acquire.

The value of EXCO's offers will be based on the PV-10 of the producing properties within each quarterly tranche of wells that have been on production for approximately one year. The pricing used in determining the PV-10 value will be based on NYMEX WTI futures contracts for 60 months then held constant for oil and NYMEX Henry Hub futures contracts for 60 months then held constant for natural gas. If EXCO and our joint venture partner are unable to agree upon the PV-10 value, an independent external engineering firm will be engaged to provide an independent valuation. The required return utilized in the offer acceptance process is based on 120% of our joint venture partner's total invested capital for the wells within each quarterly tranche. The total invested capital used in the calculation of required return is reduced by the cash flows from the production of the wells prior to the offer date. Our joint venture partner was required to accept our offers for Committed Wells if they exceed the required return. The agreement contains a provision that stipulates if the total of the offers for Committed Wells during the first four quarters of the offer process do not exceed the required return thresholds, then our joint venture partner will no longer be required to accept future offers. Since our offers for the wells included in the first four quarters of the offer process did not meet the established return thresholds, we elected not to increase our offer to meet the thresholds and therefore our joint venture partner will no longer be required to accept future offers for Committed Wells that meet the established return thresholds. However, we are required to continue to offer to purchase wells under the agreement and our joint venture partner will retain the ability to accept or decline our offer.

If the PV-10 value exceeds our joint venture partner's required return on investment, then EXCO and our joint venture partner will share the excess returns in the determination of the purchase price. This will result in a purchase price less than the PV-10 value.

These acquisitions are expected to increase the borrowing base under the revolving commitment of the EXCO Resources Credit Agreement and are expected to be funded with borrowings under the EXCO Resources Credit Agreement, cash flows from operations, or other financing arrangements. Our joint venture partner has the right to participate in certain wells drilled in the Eagle Ford shale outside of the core area, as defined under the Participation Agreement, however these wells are not included as part of the acquisition program. If our joint venture partner elects to participate in certain wells outside of our core area, we will share equally in the working interest of the well.

As of December 31, 2015, we had spud 92 gross wells and turned-to-sales 87 gross wells since the inception of the Participation Agreement. The most recent well subject to the Participation Agreement was drilled in the first quarter of 2015 and our development plans do not include drilling any additional wells subject to the Participation Agreement during 2016. The timing of these offers is dependent upon the date these wells are turned-to-sales, downtime during the year preceding the offer process and other factors. As of December 31, 2015, we had approximately 63 gross locations remaining to be drilled in the area under the Participation Agreement. The future development plans in this region are dependent on market conditions and operational decisions that impact the number of locations including spacing between wells, lateral lengths and other factors. Furthermore, any of the remaining locations that are not drilled prior to July 31, 2018 will not be subject to the offer process.

During the fourth quarter of 2015, our Eagle Ford joint venture partner purported to accept our third quarterly offer under the Participation Agreement to purchase interests in 21 gross (10.3 net) for approximately $42.7 million, subject to purchase price adjustments subsequent to the effective date of June 30, 2015. We notified our joint venture partner that we do not intend to close this acquisition and our joint venture partner filed a petition for injunctive relief and damages alleging that, among other things, we breached our obligation under the Participation Agreement. The court denied our joint venture partner's motion for injunctive relief and their request to restrain us from disbursing proceeds from the production of the assets. We filed a counterclaim seeking a declaratory judgment that, among other things, we are not obligated to purchase the disputed wells as our partner's purported acceptance had not been received in a timely manner under the terms of the Participation Agreement. In addition, quarterly offers four and five are also now in dispute for various reasons. We cannot estimate or predict the outcome of the litigation with the our joint venture partner and we may not have sufficient funds or borrowing capacity under the EXCO Resources Credit Agreement to complete any acquisitions pursuant to the Participation Agreement or pay any damages for failure to complete a purchase that a court may determine, including the wells related to the claim by our joint venture partner. In the event we fail to purchase a group of wells that we are required to make an offer on, there are remedies available to our joint venture partner which allow them to reject our future offers, terminate the Participation Agreement, remove EXCO as the operator or pursue other legal remedies.

We currently estimate that 40 to 50 additional gross wells will qualify to be included in offers during 2016. However, the extent and timing of these offers in future periods will be dependent on the terms and conditions of the offer process and the resolution of the previously mentioned dispute with our joint venture partner. The amounts for future offers or acquisitions will depend on future reserves, commodity prices, capital expenditures, production, revenues, expenses, as well as our joint venture partner's intentions to accept offers and exercise their right to retain an interest. As such, it is not possible to reasonably estimate the amounts for future offers or acquisitions under the agreement.

Historical sources and uses of funds

Our primary sources of cash in 2015 were cash flows from operations, proceeds received from the issuance of the Fairfax Term Loan and borrowings under the EXCO Resources Credit Agreement.

Net increases (decreases) in cash are summarized as follows:

(in thousands)	Year Ended December 31, 2015	2014	2013
Net cash provided by operating activities	$ 134,027	$ 362,093	$ 350,634
Net cash used in investing activities	(300,833)	(221,588)	(252,478)
Net cash provided by (used in) financing activities	132,748	(144,683)	(93,317)
Net increase (decrease) in cash	$ (34,058)	$ (4,178)	$ 4,839

Operating activities

The primary factors impacting our cash flows from operating activities generally include: (i) levels of production from our oil and natural gas properties, (ii) prices we receive from sales of oil and natural gas production, including settlement proceeds or payments related to our oil and natural gas derivatives, (iii) operating costs of our oil and natural gas properties, (iv) costs of our general and administrative activities and (v) interest expense. Our cash flows from operating activities have historically been impacted by fluctuations in oil and natural gas prices and our production volumes.

For the year ended December 31, 2015, our net cash provided by operating activities was $134.0 million as compared to $362.1 million for the year ended December 31, 2014. The decrease was primarily attributable to lower revenues from lower production and decreased oil and natural gas prices. In addition, the decrease was due to changes in accounts payable resulting from lower advance billings to other working interest owners in the Eagle Ford shale as well as lower revenues payable to other owners. The decrease was partially offset by cash receipts of $128.8 million on derivative contracts for the year ended December 31, 2015 compared to cash payments of $19.0 million for the same period in the prior year.

For the year ended December 31, 2014, our net cash provided by operating activities was $362.1 million as compared to $350.6 million for the year ended December 31, 2013. The increase is primarily attributable to higher revenues from the Haynesville and Eagle Ford shale assets we acquired in 2013 as well as an increase in natural gas prices. This was partially offset by lower natural gas production as well as a decrease in oil prices. In addition, the increase was due to changes in accounts receivable which provided cash of $52.0 million for the year ended December 31, 2014 as compared to $46.2 million of cash used for the year ended December 31, 2013. The decrease in accounts receivable for the year end December 31, 2014 as compared to prior year was primarily due to timing of collections of our oil and natural gas sales. This was partially offset by cash payments of $19.0 million on derivative contracts for the year ended December 31, 2014 compared to cash receipts of $42.1 million in the prior year.

Investing activities

Our investing activities consist primarily of drilling and development expenditures, acquisitions and divestitures. Future acquisitions are dependent on oil and natural gas prices, availability of attractive acreage and other oil and natural gas properties, acceptable rates of return, availability of borrowing capacity under the EXCO Resources Credit Agreement and availability of other sources of capital.

For the year ended December 31, 2015, our net cash used in investing activities was $300.8 million primarily due to our drilling and completion activities in the East Texas, North Louisiana and South Texas regions. The cash used in investing activities for the year ended December 31, 2015 included a significant amount of expenditures related to the wells drilled in 2014.

For the year ended December 31, 2014, our net cash used in investing activities was $221.6 million which consisted of $391.8 million of drilling and development activities in the North Louisiana, South Texas and East Texas regions. This was partially offset by $118.8 million of proceeds received from the sale of our interest in Compass and approximately $68.2 million of proceeds received from the sale of our interest in certain non-operated assets in the Permian Basin.

For the year ended December 31, 2013, our cash flows used in investing activities were $252.5 million. Our property acquisitions during 2013 were primarily attributable to the acquisition of Haynesville and Eagle Ford assets of $942.9 million and our proportionate share of Compass's acquisition of the shallow Cotton Valley assets from an affiliate of BG Group. Our capital expenditures of $320.5 million were primarily focused on our development program in the North Louisiana and South Texas regions. The cash used in investing activities was partially offset by the $574.8 million in proceeds as a result of the contribution of properties to Compass, the sale of our equity investment in TGGT of $236.6 million, net of commissions and fees, the sale of undeveloped acreage in South Texas for $130.9 million and other asset divestitures of $37.9 million.

Financing activities

For the year ended December 31, 2015, our net cash provided by financing activities was $132.7 million primarily due to $300.0 million of proceeds received from the Fairfax Term Loan and $165.0 million in borrowings under the EXCO Resources Credit Agreement. We used the proceeds from the Fairfax Term Loan to repay the outstanding indebtedness under the EXCO Resources Credit Agreement. The issuance of the Exchange Term Loan and the related retirements of the 2018 and 2022 Notes were conducted simultaneously with the same creditors and did not impact our cash flows from financing activities. In addition, we used cash to pay $20.9 million of deferred financing costs primarily related to recent debt restructuring activities, repurchase a portion of the 2018 Notes for $12.0 million and a cash payment of $8.8 million that reduced the carrying value of the Exchange Term Loan. As discussed in "Note 5. Debt" in the Notes to our Consolidated Financial Statements, all cash payments under the terms of the Exchange Term Loan, whether designated as interest or as principal amount, will reduce the carrying amount and no interest expense will be recognized.

For the year ended December 31, 2014, our net cash used in financing activities was $144.7 million primarily due to $859.9 million in net payments of outstanding indebtedness under the EXCO Resources Credit Agreement, $41.1 million of dividend payments and $10.3 million of deferred financing costs primarily related to issuance of the 2022 Notes. This was offset by $500.0 million of gross proceeds received from issuance of the 2022 Notes and approximately $272.9 million of gross proceeds received from the Rights Offering.

For the year ended December 31, 2013, our cash flows used in financing activities were $93.3 million. The cash flows used in financing activities were primarily attributable to net borrowings under the EXCO Resources Credit Agreement to fund the acquisition of the Haynesville and Eagle Ford assets and the additional borrowings of Compass to fund the acquisition of shallow Cotton Valley assets. In addition, we paid $33.6 million of deferred financing costs associated with amendments to the EXCO Resources Credit Agreement and we paid $43.2 million of dividends on our common shares during 2013.

Capital expenditures

During 2015, our capital expenditures, including oil and natural gas property acquisitions, totaled $284.8 million, of which $228.5 million was related to drilling and development activities. Our development program during 2015 included an average of three operated drilling rigs focused primarily on the Haynesville and Bossier shales in the Shelby area of East Texas. Our development activities in North Louisiana during 2015 included limited drilling as well as completion activities in Caddo and DeSoto Parishes, Louisiana. Our development program in the South Texas region included an average of one operated drilling rig focused on the Eagle Ford shale and the Buda formation. Our capital expenditures in the South Texas region also included the leasing of acreage in Zavala County, Texas. As a result of the decline in oil prices, we suspended our drilling in the South Texas region in the fourth quarter of 2015. We drilled an appraisal well in the Marcellus shale in Northeast Pennsylvania which is expected to be turned-to-sales at a later date as it is currently awaiting construction of a gathering line. In response to the downturn in commodity prices, we have negotiated reductions in service costs with certain key vendors utilized in our drilling and completion activities and continue to pursue further reductions.

During 2014, our capital expenditures, including oil and natural gas property acquisitions, totaled $434.8 million, of which $356.3 million was related to drilling and development activities. Our development program during 2014 primarily focused on our properties in the Haynesville, Bossier and Eagle Ford shales. During 2014, we operated three to six operated drilling rigs in the Haynesville and Bossier shales focused on our core area in DeSoto Parish, Louisiana and the Shelby area of East Texas. Our capital expenditures in this region also included re-fracture stimulation treatments on 5 gross (2.8 net) mature Haynesville shale wells. Our development program in the Eagle Ford shale focused on our core area in Zavala County, Texas and limited drilling outside our core area as part of a farmout agreement. We operated two to five operated drilling rigs in this region during 2014. We also installed pumping units on 87 gross (45.6 net) wells in the region to optimize our production. Our development activities during the year featured enhanced drilling and completion techniques which improved our well performance while we efficiently managed our capital expenditures.

During 2013, our capital expenditures primarily consisted of our acquisitions of Haynesville and Eagle Ford assets as well as our development programs in these regions. The oil and natural gas property acquisitions of $942.9 million during 2013 included the Eagle Ford and Haynesville assets acquired from Chesapeake. In connection with closing the acquisition of the Eagle Ford assets, we entered into a Participation Agreement with a joint venture partner and sold an undivided 50%

interest in the undeveloped acreage we acquired for approximately $130.9 million. Our development program during 2013 focused on our properties in the Haynesville and Eagle Ford shales. We operated three drilling rigs throughout 2013 in the Haynesville shale focused on our core area in DeSoto and Caddo Parish, Louisiana. We began our development program in the Eagle Ford shale which included three to four operated drilling rigs from the date we acquired the properties to year-end. We also incurred additional expenditures in this region for surface acreage, infrastructure and operating facilities. Our expenditures in the Appalachia region focused on a limited appraisal drilling program, completion activities and the construction of pads for future drilling activity.

The following table presents our capital expenditures for the years ended December 31, 2015, 2014 and 2013.

(in thousands)	Year Ended December 31, 2015	2014	2013
Capital expenditures:			
Lease purchases and seismic	$ 13,364	$ 10,477	$ 25,052
Development capital expenditures	228,545	356,344	265,120
Field operations, gathering and water pipelines	6,672	20,256	12,379
Corporate and other	28,602	37,198	37,287
Total capital expenditures excluding oil and natural gas property acquisitions	277,183	424,275	339,838
Oil and natural gas property acquisitions (1)	7,608	10,562	942,946
Total capital expenditures including oil and natural gas property acquisitions	$ 284,791	$ 434,837	$ 1,282,784

(1) The oil and natural gas property acquisitions of $942.9 million during 2013 included the Eagle Ford and Haynesville assets. This amount was reduced by $130.9 million from the sale of a portion of the undeveloped acreage we acquired in the Eagle Ford shale to a joint venture partner.

2016 capital budget

Our Board of Directors approved a budget of $70.0 million to fund drilling through the first half of 2016 and the related completion activities in North Louisiana and East Texas. The approved capital budget also includes $33.0 million to fund field operations, land, capitalized corporate costs and other expenditures for the full year 2016. During 2016, we will continue to evaluate market conditions and recommend approval from the Board of Directors for the drilling and completion budget for the second half of the year. EXCO expects to fund the capital budget with cash flow from operations and borrowings under the EXCO Resources Credit Agreement.

The drilling and completion activities for the first six months of 2016 in the Holly area in North Louisiana are expected to include similar completion methods that have proven to be successful in our East Texas region, including the use of more proppant, modified well spacing and longer laterals. Our development in East Texas is anticipated to focus on completing and turning to sales wells drilled in the Shelby area during 2015. We have suspended our drilling activity in South Texas and Appalachia in response to low commodity prices. We have flexibility in the timing of development in both South Texas and Appalachia because a significant portion of our acreage in these regions is held-by-production. The 2016 capital budget is currently allocated among the different budget categories as follows:

(in millions, except wells)	Gross Wells Spud (1)	Net Wells Spud (1)	Net Wells Completed (1)	Drilling & Completion	Other Capital (2)	Total Capital
North Louisiana	9	5.5	5.5	$ 42.0	$ 3.0	$ 45.0
East Texas	—	—	4.1	28.0	6.0	34.0
South Texas	—	—	—	—	5.0	5.0
Appalachia	—	—	—	—	5.0	5.0
Corporate and other (3)	—	—	—	—	14.0	14.0
Total	9	5.5	9.6	$ 70.0	$ 33.0	$ 103.0

(1) The wells spud and completed within this table only include those operated by EXCO. This represents drilling activities through the first half of 2016 and the related completion activities.
(2) Other capital includes field operations, land, capitalized corporate costs and other expenditures for the full year 2016.
(3) Includes $9.0 million of capitalized interest and $5.0 million of capitalized general and administrative expenses for the full year 2016.

Derivative financial instruments

Our production is generally sold at prevailing market prices. However, we periodically enter into oil and natural gas derivative contracts for a portion of our production when market conditions are deemed favorable and oil and natural gas prices exceed our minimum internal price targets. Our objective in entering into oil and natural gas derivative contracts is to mitigate the impact of commodity price fluctuations and achieve a more predictable cash flow associated with our operations. These transactions limit our exposure to declines in prices, but also limit the benefits we would realize if oil and natural gas prices increase.

Our derivative financial instruments were comprised of oil and natural gas swaps as of December 31, 2015. We had derivative financial instruments in place for the volumes and prices shown below:

	NYMEX gas volume - Bbtu	Weighted average contract price per Mmbtu	NYMEX oil volume - Mbbl	Weighted average contract price per Bbl
Swaps:				
2016	34,770	$ 3.09	915	$ 61.89
2017	10,950	3.28	—	—
2018	3,650	3.15	—	—

Since December 31, 2015, we entered into swaption contracts that included fixed price swaps covering 6,700 Bbtu of natural gas at a price of $2.76 per Mmbtu for 2016 in exchange for an option on behalf of the counterparty to swap 7,300 Bbtu of natural gas at a price of $2.76 per Mmbtu for 2017. We also entered into fixed price swaps covering 12,200 Bbtu of natural gas at an average price of $2.45 per Mmbtu for 2016 and 1,800 Bbtu of natural gas at a price of $2.36 per Mmbtu for 2017.

See further details on our derivative financial instruments in "Note 4. Derivative financial instruments" and "Note 6. Fair value measurements" in the Notes to our Consolidated Financial Statements.

Off-balance sheet arrangements

As of December 31, 2015, we had no arrangements or any guarantees of off-balance sheet debt to third parties.

Contractual obligations and commercial commitments

The following table presents our contractual obligations and commercial commitments as of December 31, 2015 and do not include those of our equity method investments.

	Payments due by period				
(in thousands)	**Less than one year**	**One to three years**	**Three to five years**	**More than five years**	**Total**
EXCO Resources Credit Agreement (1)	$ —	$ 67,492	$ —	$ —	$ 67,492
Senior Notes (2)	—	158,015	—	222,826	380,841
Exchange Term Loan (3)	—	—	400,000	—	400,000
Fairfax Term Loans (4)	—	—	300,000	—	300,000
Gathering and firm transportation services (5)	120,414	236,450	124,433	135,943	617,240
Other fixed commitments (6)	13,253	8,653	4,335	1,599	27,840
Drilling contracts (7)	14,997	7,284	—	—	22,281
Operating leases and other	5,456	7,468	4,613	72	17,609
Total contractual obligations	$ 154,120	$ 485,362	$ 833,381	$ 360,440	$ 1,833,303

(1) The EXCO Resources Credit Agreement matures on July 31, 2018. The interest rate grid on the revolving credit facility of the EXCO Resources Credit Agreement ranges from LIBOR plus 225 bps to 325 bps (or ABR plus 125 bps to 225 bps), depending on the percentages of drawn balances to the borrowing base.

(2) The 2018 Notes are due on September 15, 2018 and the 2022 Notes are due on April 15, 2022. Based on the outstanding principal balance at December 31, 2015, the annual interest obligation on the 2018 Notes and 2022 Notes is $11.9 million and $18.9 million, respectively. We expect our annual interest obligation on the 2018 Notes and 2022 Notes to decrease in 2016 as a result of notes repurchases in 2016. See "Note 5. Debt" in the Notes to our Consolidated Financial Statements for additional information on the 2016 notes repurchases.

(3) The Exchange Term Loan matures on October 26, 2020. The amount presented in the table above is the principal balance outstanding. The annual cash payment on the Exchange Term Loan is $50.0 million based on the interest rate of 12.5% per annum. See "Note 5. Debt" in the Notes to our Consolidated Financial Statements for additional information and the accounting treatment of the Exchange Term Loan.

(4) The Fairfax Term Loan matures on October 26, 2020. The annual interest obligation is $37.5 million.

(5) Gathering and firm transportation services reflect contracts whereby EXCO commits to transport a minimum quantity of natural gas on a gatherer's system or a shippers' pipeline. Whether or not EXCO delivers the minimum quantity, we pay the fees as if the quantities were delivered. These expenses represent our gross commitments under these contracts and a portion of these costs will be incurred by working interest and other owners. As described in "Note 2. Summary of significant accounting policies" in the Notes to our Consolidated Financial Statements, we report these costs as gathering and transportation expenses or as a reduction in total sales price received from the purchaser. In addition, our variable rate firm transportation contracts do not have a minimum volume commitment and are not included in the table above. As such, our gathering and firm transportation services presented in the table above may not be representative of the amounts reported as gathering and transportation expenses in our Consolidated Financial Statements. Effective January 1, 2016, EXCO renegotiated a sales contract which reduced the contracted price from $0.35 per Mmbtu to $0.25 per Mmbtu for 75,000 Mmbtu per day that we are obligated to deliver and extended the term of the contract for four years.

(6) Other fixed commitments are primarily related to completion service contracts and minimum sales commitments under marketing contracts.

(7) Drilling contracts represent the contractual rate for our operated rigs through the term of the contracts as of December 31, 2015. The actual drilling costs under these contracts will be incurred by working interest owners in the development of the related properties.

Item 7A. Quantitative and Qualitative Disclosures About Market Risk

Some of the information below contains forward-looking statements. The primary objective of the following information is to provide forward-looking quantitative and qualitative information about our potential exposure to market risks. The term "market risk" refers to the risk of loss arising from adverse changes in oil and natural gas prices, interest rates charged on borrowings and earned on cash equivalent investments, and adverse changes in the market value of marketable securities. The disclosure is not meant to be a precise indicator of expected future losses, but rather an indicator of reasonably possible losses. This forward-looking information provides an indicator of how we view and manage our ongoing market risk exposures. Our market risk sensitive instruments were entered into for hedging and investment purposes, not for trading purposes.

Commodity price risk

Our objective in entering into derivative financial instruments is to manage our exposure to commodity price fluctuations, protect our returns on investments, and achieve a more predictable cash flow in connection with our financing activities and borrowings related to these activities. These transactions limit exposure to declines in prices, but also limit the benefits we would realize if oil and natural gas prices increase. When prices for oil and natural gas are volatile, a significant portion of the effect of our derivative financial instrument management activities consists of non-cash income or expense due to changes in the fair value of our derivative financial instrument contracts. Cash losses or gains only arise from payments made or received on monthly settlements of contracts or if we terminate a contract prior to its expiration.

Our most significant market risk exposure is in the pricing applicable to our oil and natural gas production. Realized pricing is primarily driven by the prevailing worldwide price for crude oil and spot market prices for natural gas. Pricing for oil and natural gas production is volatile.

Our use of derivative financial instruments could have the effect of reducing our revenues and the value of our securities. For the year ended December 31, 2015, a $1.00 increase in the average commodity price per Mcfe would have resulted in an increase in cash settlement payments (or a decrease in settlements received) of approximately $56.5 million for our oil and natural gas swap contracts. The ultimate settlement amount of our outstanding derivative financial instrument contracts is dependent on future commodity prices. We may incur significant unrealized losses in the future from our use of derivative financial instruments to the extent market prices increase and our derivatives contracts remain in place.

Interest rate risk

At December 31, 2015, our exposure to interest rate changes related primarily to borrowings under the EXCO Resources Credit Agreement. The interest rates per annum on the 2018 Notes, 2022 Notes and the Second Lien Term Loans are fixed at 7.5%, 8.5% and 12.5%, respectively. Interest is payable on borrowings under the EXCO Resources Credit Agreement based on a floating rate as more fully described in "Note 5. Debt" in the Notes to our Consolidated Financial Statements. At December 31, 2015, we had approximately $67.5 million in outstanding borrowings under the EXCO Resources Credit

Agreement. A 1% increase in interest rates (100 bps) based on the variable borrowings as of December 31, 2015 would result in an increase in our interest expense of approximately $0.7 million per year. The interest we pay on these borrowings is set periodically based upon market rates.

Item 8. Financial Statements and Supplementary Data

EXCO Resources, Inc.

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Management's Report on Internal Control Over Financial Reporting

To the Board of Directors and Shareholders of
EXCO Resources, Inc.:

Management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) under the Securities Exchange Act of 1934, as amended). Our internal control over financial reporting is designed to provide reasonable assurance to management and our Board of Directors regarding the preparation and fair presentation of published financial statements. Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015. In making this assessment, management used the criteria set forth by the Committee of Sponsoring Organizations of the Treadway Commission ("COSO") in *Internal Control-Integrated Framework (2013)*. Based on management's assessment, management believes that, as of December 31, 2015, our internal control over financial reporting was effective based on those criteria.

The effectiveness of EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2015 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report which appears herein.

By:	/s/ Harold L. Hickey	By:	/s/ Richard A. Burnett
Title:	Chief Executive Officer and President	Title:	Vice President, Chief Financial Officer and Chief Accounting Officer

Dallas, Texas
March 2, 2016

Report of Independent Registered Public Accounting Firm

The Board of Directors and Shareholders
EXCO Resources, Inc.:

We have audited the accompanying consolidated balance sheets of EXCO Resources, Inc. and subsidiaries as of December 31, 2015 and 2014, and the related consolidated statements of operations, cash flows, and changes in shareholders' equity for each of the years in the three-year period ended December 31, 2015. We also have audited EXCO Resources, Inc.'s internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). EXCO Resources, Inc.'s management is responsible for these consolidated financial statements, 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 these consolidated financial statements and an opinion on the Company's internal control over financial reporting 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 audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the consolidated financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

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 consolidated financial statements referred to above present fairly, in all material respects, the financial position of EXCO Resources, Inc. and subsidiaries as of December 31, 2015 and 2014, and the results of its operations and its cash flows for each of the years in the three-year period ended December 31, 2015, in conformity with U.S. generally accepted accounting principles. Also in our opinion, EXCO Resources, Inc. maintained, in all material respects, effective internal control over financial reporting as of December 31, 2015, based on criteria established in Internal Control - Integrated Framework (2013) issued by the Committee of Sponsoring Organizations of the Treadway Commission.

/s/ KPMG LLP

Dallas, Texas
March 2, 2016

EXCO RESOURCES, INC.

CONSOLIDATED BALANCE SHEETS

(in thousands)	December 31, 2015	December 31, 2014
Assets		
Current assets:		
Cash and cash equivalents	$ 12,247	$ 46,305
Restricted cash	21,220	23,970
Accounts receivable, net:		
Oil and natural gas	37,236	81,720
Joint interest	22,095	65,398
Other	8,894	8,945
Derivative financial instruments	39,499	97,278
Inventory and other	8,610	7,150
Total current assets	149,801	330,766
Equity investments	40,797	55,985
Oil and natural gas properties (full cost accounting method):		
Unproved oil and natural gas properties and development costs not being amortized	115,377	276,025
Proved developed and undeveloped oil and natural gas properties	3,070,430	3,852,073
Accumulated depletion	(2,627,763)	(2,414,461)
Oil and natural gas properties, net	558,044	1,713,637
Other property and equipment, net	27,812	24,644
Deferred financing costs, net	8,408	14,617
Derivative financial instruments	6,109	2,138
Goodwill	163,155	163,155
Total assets	$ 954,126	$ 2,304,942
Liabilities and shareholders' equity		
Current liabilities:		
Accounts payable and accrued liabilities	$ 85,254	$ 110,211
Revenues and royalties payable	106,163	152,651
Drilling advances	2,795	37,648
Accrued interest payable	7,846	26,265
Current portion of asset retirement obligations	845	1,769
Income taxes payable	—	—
Derivative financial instruments	16	892
Current portion of long-term debt	50,000	—
Total current liabilities	252,919	329,436
Long-term debt	1,320,279	1,430,516
Asset retirement obligations and other long-term liabilities	43,251	34,986
Commitments and contingencies		
Shareholders' equity:		
Common shares, $0.001 par value; 780,000,000 authorized shares; 283,633,996 shares issued and 283,039,333 shares outstanding at December 31, 2015; 274,351,756 shares issued and 273,773,714 shares outstanding at December 31, 2014	276	270
Additional paid-in capital	3,522,153	3,502,209
Accumulated deficit	(4,177,120)	(2,984,860)
Treasury shares, at cost; 594,663 at December 31, 2015 and 578,042 at December 31, 2014	(7,632)	(7,615)
Total shareholders' equity	(662,323)	510,004
Total liabilities and shareholders' equity	$ 954,126	$ 2,304,942

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF OPERATIONS

(in thousands, except per share data)	Year Ended December 31, 2015	2014	2013
Revenues:			
Oil	$ 102,787	$ 196,316	$ 111,440
Natural gas	225,544	463,953	522,869
Total revenues	328,331	660,269	634,309
Costs and expenses:			
Oil and natural gas operating costs	53,903	64,467	61,277
Production and ad valorem taxes	22,630	29,859	21,971
Gathering and transportation	99,321	101,574	100,645
Depletion, depreciation and amortization	215,426	263,569	245,775
Impairment of oil and natural gas properties	1,215,370	—	108,546
Accretion of discount on asset retirement obligations	2,277	2,690	2,514
General and administrative	58,818	65,920	91,878
(Gain) loss on divestitures and other operating items	461	5,315	(177,518)
Total costs and expenses	1,668,206	533,394	455,088
Operating income (loss)	(1,339,875)	126,875	179,221
Other income (expense):			
Interest expense, net	(106,082)	(94,284)	(102,589)
Gain (loss) on derivative financial instruments	75,869	87,665	(320)
Gain on restructuring and extinguishment of debt	193,276	—	—
Other income (expense)	122	241	(828)
Equity income (loss)	(15,691)	172	(53,280)
Total other income (expense)	147,494	(6,206)	(157,017)
Income (loss) before income taxes	(1,192,381)	120,669	22,204
Income tax expense	—	—	—
Net income (loss)	$ (1,192,381)	$ 120,669	$ 22,204
Earnings (loss) per common share:			
Basic:			
Net income (loss)	$ (4.36)	$ 0.45	$ 0.10
Weighted average common shares outstanding	273,621	268,258	215,011
Diluted:			
Net income (loss)	$ (4.36)	$ 0.45	$ 0.10
Weighted average common shares and common share equivalents outstanding	273,621	268,376	230,912

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CASH FLOWS

(in thousands)	Year Ended December 31, 2015	2014	2013
Operating Activities:			
Net income (loss)	$ (1,192,381)	$ 120,669	$ 22,204
Adjustments to reconcile net income (loss) to net cash provided by operating activities:			
Depletion, depreciation and amortization	215,426	263,569	245,775
Equity-based compensation expense	7,198	4,962	10,748
Accretion of discount on asset retirement obligations	2,277	2,690	2,514
Impairment of oil and natural gas properties	1,215,370	—	108,546
(Income) loss from equity investments	15,691	(172)	53,280
(Gain) loss on derivative financial instruments	(75,869)	(87,665)	320
Cash settlements (payments) of derivative financial instruments	128,800	(18,991)	42,119
Amortization of deferred financing costs and discount on debt issuance	16,994	12,055	29,624
Gain on divestitures and other non-operating items	(32)	(17)	(185,163)
Gain on restructuring and extinguishment of debt	(193,276)	—	—
Effect of changes in:			
Restricted cash with related party	(2,100)	—	—
Accounts receivable	88,610	52,007	(46,176)
Other current assets	434	(2,609)	9,627
Accounts payable and other current liabilities	(93,115)	15,595	57,216
Net cash provided by operating activities	134,027	362,093	350,634
Investing Activities:			
Additions to oil and natural gas properties, gathering assets and equipment	(317,590)	(391,776)	(320,538)
Property acquisitions	(7,608)	(10,790)	(976,714)
Proceeds from disposition of property and equipment	7,397	187,655	749,628
Restricted cash	4,850	(3,400)	49,515
Net changes in advances to joint ventures	10,663	(5,026)	10,645
Equity investments and other	1,455	1,749	234,986
Net cash used in investing activities	(300,833)	(221,588)	(252,478)
Financing Activities:			
Borrowings under credit agreements	165,000	100,000	1,004,523
Repayments under credit agreements	(300,000)	(964,970)	(1,022,785)
Proceeds received from issuance of 2022 Notes	—	500,000	—
Repurchases of 2018 Notes	(12,008)	—	—
Proceeds received from issuance of Fairfax Term Loan	300,000	—	—
Payment on Exchange Term Loan	(8,827)	—	—
Proceeds from issuance of common shares, net	9,693	271,773	1,712
Payment of common share dividends	(164)	(41,060)	(43,214)
Deferred financing costs and other	(20,946)	(10,426)	(33,553)
Net cash provided by (used in) financing activities	132,748	(144,683)	(93,317)
Net increase (decrease) in cash	(34,058)	(4,178)	4,839
Cash at beginning of period	46,305	50,483	45,644
Cash at end of period	$ 12,247	$ 46,305	$ 50,483
Supplemental Cash Flow Information:			
Cash interest payments	$ 117,463	$ 91,735	$ 88,936
Income tax payments	—	—	—
Supplemental non-cash investing and financing activities:			
Capitalized equity-based compensation	$ 3,428	$ 5,498	$ 7,288
Capitalized interest	12,040	20,060	18,729
Issuance of common shares for director services	150	235	93
Debt eliminated upon sale of Compass and assumed upon formation of Compass, net for the years ended December 31, 2014 and 2013, respectively	—	(83,246)	58,613

See accompanying notes.

EXCO RESOURCES, INC.

CONSOLIDATED STATEMENTS OF CHANGES IN SHAREHOLDERS' EQUITY

(in thousands)	Common Shares: Shares	Common Shares: Amount	Subscription Rights: Shares	Subscription Rights: Amount	Treasury Shares: Shares	Treasury Shares: Amount	Additional paid-in capital	Accumulated deficit	Total shareholders' equity
Balance at December 31, 2012	218,126	$ 215	—	$ —	(539)	$ (7,479)	$ 3,200,067	$ (3,043,410)	$ 149,393
Issuance of common shares	228	—	—	—	—	—	1,805	—	1,805
Equity-based compensation	—	—	—	—	—	—	17,931	—	17,931
Restricted shares issued, net of cancellations	429	—	—	—	—	—	—	—	—
Common share dividends	—	—	—	—	—	—	—	(43,428)	(43,428)
Issuance of subscription rights	—	—	54,575	55	—	—	(55)	—	—
Net income	—	—	—	—	—	—	—	22,204	22,204
Balance at December 31, 2013	218,783	$ 215	54,575	$ 55	(539)	$ (7,479)	$ 3,219,748	$ (3,064,634)	$ 147,905
Issuance of common shares	54,582	55	(54,575)	(55)	—	—	272,008	—	272,008
Equity-based compensation	—	—	—	—	—	—	10,453	—	10,453
Restricted shares issued, net of cancellations	987	—	—	—	—	—	—	—	—
Common share dividends	—	—	—	—	—	—	—	(40,895)	(40,895)
Treasury share repurchase	—	—	—	—	(39)	(136)	—	—	(136)
Net income	—	—	—	—	—	—	—	120,669	120,669
Balance at December 31, 2014	274,352	$ 270	—	$ —	(578)	$ (7,615)	$ 3,502,209	$ (2,984,860)	$ 510,004
Issuance of common shares	5,882	6	—	—	—	—	9,838	—	9,844
Equity-based compensation	—	—	—	—	—	—	10,106	—	10,106
Restricted shares issued, net of cancellations	3,400	—	—	—	—	—	—	—	—
Common share dividends	—	—	—	—	—	—	—	121	121
Treasury share repurchases	—	—	—	—	(17)	(17)	—	—	(17)
Net loss	—	—	—	—	—	—	—	(1,192,381)	(1,192,381)
Balance at December 31, 2015	283,634	$ 276	—	$ —	(595)	$ (7,632)	$ 3,522,153	$ (4,177,120)	$ (662,323)

See accompanying notes.

1. Organization and basis of presentation

Unless the context requires otherwise, references in this Annual Report on Form 10-K to "EXCO," "EXCO Resources," "Company," "we," "us," and "our" are to EXCO Resources, Inc. and its consolidated subsidiaries.

We are an independent oil and natural gas company engaged in the exploration, exploitation, acquisition, development and production of onshore U.S. oil and natural gas properties with a focus on shale resource plays. Our principal operations are conducted in certain key U.S. oil and natural gas areas including Texas, Louisiana and the Appalachia region. The following is a brief discussion of our producing regions.

- ***East Texas and North Louisiana***

  The East Texas and North Louisiana regions are primarily comprised of our Haynesville and Bossier shale assets. We have a joint venture with BG Group, plc ("BG Group") covering an undivided 50% interest in certain Haynesville/Bossier shale assets in East Texas and North Louisiana. The East Texas and North Louisiana regions also include assets outside of the joint venture in the Haynesville and Bossier shales. We serve as the operator for most of our properties in both the East Texas and North Louisiana regions.

- ***South Texas***

  The South Texas region is primarily comprised of our Eagle Ford shale assets. We have a joint venture with affiliates of Kohlberg Kravis Roberts & Co. L.P. ("KKR") covering certain assets in the Eagle Ford shale. The South Texas region also includes assets outside of the joint venture in the Eagle Ford shale, Buda and other formations. We serve as the operator for most of our properties in the South Texas region.

- ***Appalachia***

  The Appalachia region is primarily comprised of Marcellus shale assets as well as shallow conventional assets in other formations. We have a joint venture with BG Group covering our shallow conventional assets and Marcellus shale assets in the Appalachia region ("Appalachia JV"). EXCO and BG Group each own an undivided 50% interest in the Appalachia JV and a 49.75% working interest in the Appalachia JV's properties. The remaining 0.5% working interest is held by a jointly owned operating entity ("OPCO") that operates the Appalachia JV's properties. We own a 50% interest in OPCO.

The accompanying Consolidated Balance Sheets as of December 31, 2015 and 2014, Consolidated Statements of Operations, Consolidated Statements of Cash Flows and Consolidated Statements of Changes in Shareholders' Equity for the years ended December 31, 2015, 2014 and 2013 are for EXCO and its subsidiaries. The consolidated financial statements and related footnotes are presented in accordance with generally accepted accounting principles in the United States ("GAAP"). Certain reclassifications have been made to prior period information to conform to current period presentation.

2. Summary of significant accounting policies

Principles of consolidation

We consolidate all of our subsidiaries in the accompanying Consolidated Balance Sheets as of December 31, 2015 and 2014 and the Consolidated Statements of Operations, Consolidated Statements of Cash Flows and Changes in Shareholders' Equity for the years ended December 31, 2015, 2014 and 2013. Investments in unconsolidated affiliates in which we are able to exercise significant influence are accounted for using the equity method. We use the cost method of accounting for investments in unconsolidated affiliates in which we are not able to exercise significant influence. All intercompany transactions and accounts have been eliminated.

We report our interests in oil and natural gas properties using the proportional consolidation method of accounting. We reported our 25.5% interest in Compass Production Partners, L.P. ("Compass") using proportional consolidation for the period from its formation on February 14, 2013 to the sale of our interests on October 31, 2014. See further discussion in "Note 3. Acquisitions, divestitures and other significant events."

Management estimates

In preparing the consolidated financial statements in conformity with GAAP, we are required to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues and expenses during the reporting periods. The more significant estimates pertain to proved oil and natural gas reserve volumes, future development costs, asset retirement obligations, equity-based compensation, estimates relating to oil and natural gas revenues and expenses, accrued liabilities, the fair market value of assets and liabilities acquired in business combinations, derivatives and goodwill. Actual results may differ from management's estimates.

Cash equivalents

We consider all highly liquid investments with maturities of three months or less when purchased, to be cash equivalents.

Restricted cash

The restricted cash on our balance sheet is principally comprised of our share of an evergreen escrow account with BG Group that is used to fund our share of development operations in East Texas and North Louisiana. Funds held in this escrow account are restricted and can be used primarily for drilling and operations in East Texas and North Louisiana. The restricted cash also includes accrued fees payable to Energy Strategic Advisory Services LLC ("ESAS") upon completion of its entire first year of service and required investment with EXCO. See "Note 13. Related party transactions" for further discussion of the services and investment agreement with ESAS.

Concentration of credit risk and accounts receivable

Financial instruments that potentially subject us to a concentration of credit risk consist principally of cash, trade receivables and our derivative financial instruments. We place our cash with financial institutions which we believe have sufficient credit quality to minimize risk of loss. We sell oil and natural gas to various customers. In addition, we participate with other parties in the drilling, completion and operation of oil and natural gas wells. The majority of our accounts receivable are due from either purchasers of oil or natural gas or participants in oil and natural gas wells for which we serve as the operator. We have the right to offset future revenues against unpaid charges related to wells which we operate. Oil and natural gas receivables are generally uncollateralized. The allowance for doubtful accounts was immaterial at both December 31, 2015 and 2014. We place our derivative financial instruments with financial institutions that we believe have high credit ratings. To mitigate our risk of loss due to default, we have entered into master netting agreements with our counterparties on our derivative financial instruments that allow us to offset our asset position with our liability position in the event of a default by the counterparty.

For the years ended December 31, 2015, 2014 and 2013, sales to BG Energy Merchants LLC accounted for approximately 20%, 34% and 48%, respectively, of total consolidated revenues. BG Energy Merchants LLC is a subsidiary of BG Group. For the years ended December 31, 2015, 2014 and 2013, Chesapeake Energy Marketing Inc. accounted for approximately 38%, 31% and 14% respectively, of total consolidated revenues. Chesapeake Energy Marketing Inc. is a subsidiary of Chesapeake Energy Corporation ("Chesapeake").

Derivative financial instruments

We use derivative financial instruments to mitigate the impacts of commodity price fluctuations, protect our returns on investments and achieve a more predictable cash flow. Financial Accounting Standards Board ("FASB"), Accounting Standards Codification, ("ASC"), Topic 815, *Derivatives and Hedging,* ("ASC 815"), requires that every derivative instrument (including certain derivative instruments embedded in other contracts) be recorded on the balance sheet as either an asset or liability measured at its estimated fair value. ASC 815 requires that changes in the derivative's estimated fair value be recognized in earnings unless specific hedge accounting criteria are met, or exemptions for normal purchases and normal sales as permitted by ASC 815 exist. We do not designate our derivative financial instruments as hedging instruments and, as a result, recognize the change in a derivative's estimated fair value in earnings as a component of other income or expense. Our derivative financial instruments are not held for trading purposes.

Oil and natural gas properties

The accounting for, and disclosure of, oil and natural gas producing activities require that we choose between two GAAP alternatives: the full cost method or the successful efforts method. We use the full cost method of accounting, which involves capitalizing all acquisition, exploration, exploitation and development costs of oil and natural gas properties. Once we incur costs, they are recorded in the depletable pool of proved properties or in unproved properties, collectively, the full cost pool. Our unproved property costs, which include unproved oil and natural gas properties, properties under development, and major development projects, collectively totaled \$115.4 million and \$276.0 million as of December 31, 2015 and 2014, respectively, and are not subject to depletion. We review our unproved oil and natural gas property costs on a quarterly basis to assess for impairment or the need to transfer unproved costs to proved properties as a result of extension or discoveries from drilling operations or determination that no proved reserves are attributable to such costs. In determining whether such costs should be impaired or transferred, we evaluate lease expiration dates, recent drilling results, future development plans and current market values. Our undeveloped properties are predominantly held-by-production, which reduces the risk of impairment as a result of lease expirations. We expect these costs to be evaluated in one to seven years and transferred to the depletable portion of the full cost pool during that time. As a result of our evaluation, we impaired approximately \$88.1 million of unproved properties which were transferred to the depletable portion of the full cost pool during the year ended December 31, 2015. The impairment was recorded to reflect the estimated fair value of our undeveloped properties as a result of the decline in oil and natural gas prices. The impairment also included certain acreage expiring within the next year and related properties that were no longer part of our drilling plans. See "Note 6. Fair value measurements" for further discussion. We did not record an impairment of undeveloped properties during 2014 and recorded an impairment of \$1.0 million during 2013.

We capitalize interest on the costs related to the acquisition of undeveloped acreage in accordance with FASB ASC 835-20*, Capitalization of Interest*. When the unproved property costs are moved to proved developed and undeveloped oil and natural gas properties, or the properties are sold, we cease capitalizing interest related to these properties.

We calculate depletion using the unit-of-production method. Under this method, the sum of the full cost pool, excluding the book value of unproved properties, and all estimated future development costs less estimated salvage value are divided by the total estimated quantities of Proved Reserves. This rate is applied to our total production for the quarter, and the appropriate expense is recorded. We capitalize the portion of general and administrative costs, including share-based compensation, that is attributable to our acquisition, exploration, exploitation and development activities.

Sales, dispositions and other oil and natural gas property retirements are accounted for as adjustments to the full cost pool, with no recognition of gain or loss, unless the disposition would significantly alter the amortization rate and/or the relationship between capitalized costs and Proved Reserves.

Pursuant to Rule 4-10(c)(4) of Regulation S-X, at the end of each quarterly period, companies that use the full cost method of accounting for their oil and natural gas properties must compute a limitation on capitalized costs ("ceiling test"). The ceiling test involves comparing the net book value of the full cost pool, after taxes, to the full cost ceiling limitation defined below. In the event the full cost ceiling limitation is less than the full cost pool, we are required to record a ceiling test impairment of our oil and natural gas properties. The full cost ceiling limitation is computed as the sum of the present value of estimated future net revenues from our Proved Reserves by applying the average price as prescribed by the SEC Release No. 33-8995, less estimated future expenditures (based on current costs) to develop and produce the Proved Reserves, discounted at 10%, plus the cost of properties not being amortized and the lower of cost or estimated fair value of unproved properties included in the costs being amortized, net of income tax effects.

The ceiling test for each period presented was based on the following average spot prices, in each case adjusted for quality factors and regional differentials to derive estimated future net revenues. Prices presented in the table below are the trailing 12 month simple average spot prices at the first of the month for natural gas at Henry Hub ("HH") and West Texas Intermediate ("WTI") crude oil at Cushing, Oklahoma. The fluctuations demonstrate the volatility in oil and natural gas prices between each of the periods and have a significant impact on our ceiling test limitation.

	Average spot prices	
	Oil (per Bbl)	**Natural gas (per Mmbtu)**
December 31, 2015	\$ 50.28	\$ 2.59
December 31, 2014	94.99	4.35
December 31, 2013	96.78	3.67

For the year ended December 31, 2015, we recognized impairments to our proved oil and natural gas properties of $1.2 billion. The impairments were primarily due to the decline in oil and natural gas prices partially offset by upward revisions in the oil and natural gas reserves primarily as a result of recent modifications to our well design in the North Louisiana and East Texas regions. For the year ended December 31, 2014, we did not recognize an impairment to our proved oil and natural gas properties. For the year ended December 31, 2013, we recognized impairments of $108.5 million to our proved oil and natural gas properties. The impairments for the year ended December 31, 2013 were primarily due to low natural gas prices for the trailing 12 months at the end of the first quarter of 2013, downward revisions to the reserves of our Haynesville shale properties based on operational matters, narrowing of basis differentials between oil price indices, and higher costs associated with the gathering and transportation of our natural gas production from the Eagle Ford shale. We may incur additional impairments to our oil and natural gas properties in 2016 if oil and natural gas prices do not increase.

Under full cost accounting rules, any ceiling test impairments of oil and natural gas properties may not be reversed in subsequent periods. Since we do not designate our derivative financial instruments as hedging instruments, we are not allowed to use the impacts of the derivative financial instruments in our ceiling test computations.

The evaluation of impairment of our oil and natural gas properties includes estimates of Proved Reserves. There are numerous uncertainties inherent in estimating quantities of Proved Reserves, in projecting the future rates of production and in the timing of development activities. The accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. Results of drilling, testing and production subsequent to the date of the estimate may justify revisions of such estimate. Accordingly, reserve estimates often differ from the quantities of oil and natural gas that are ultimately recovered.

Inventory

Inventory includes tubular goods and other lease and well equipment which we plan to utilize in our ongoing exploration and development activities and is carried at the lower of cost or market value. The cost of inventory is capitalized in our full cost pool or gathering system assets once it has been placed into service.

Other property and equipment

Other property and equipment is primarily comprised of office, field and other equipment which are capitalized at cost and depreciated on a straight line basis over their estimated useful lives ranging from 3 to 15 years and the surface acreage we own in our South Texas region.

Goodwill

In accordance with FASB ASC 350-20, *Intangibles-Goodwill and Other*, goodwill is not amortized, but is tested for impairment on an annual basis, or more frequently as impairment indicators arise. Impairment tests, which involve the use of estimates related to the fair market value of the business operations with which goodwill is associated, are performed as of December 31 of each year. We performed impairment tests as of June 30, 2015 and September 30, 2015 as a result of continued depressed commodity prices and recent impairments of our oil and natural gas properties. Losses, if any, resulting from impairment tests will be reflected in operating income or loss in the Consolidated Statements of Operations.

We apply a two-part, equally weighted approach in determining the fair value of our business as part of the goodwill impairment test. We perform an income approach, which uses a discounted cash flow model to value our business, and a market approach, in which our value is determined using trading metrics and transaction multiples of peer companies. We consider our enterprise value to be the combined market capitalization plus the fair value of our debt in determining the fair value of our reporting unit and corroborate the results with the valuation model.

As a result of testing, the fair value of our business significantly exceeded the carrying value of net assets at December 31, 2015 and we did not record an impairment charge for the periods ending December 31, 2015, 2014 or 2013.

Asset retirement obligations

We apply FASB ASC 410-20, *Asset Retirement and Environmental Obligations* ("ASC 410-20") to account for estimated future plugging and abandonment costs. ASC 410-20 requires legal obligations associated with the retirement of long-lived assets to be recognized at their estimated fair value at the time that the obligations are incurred. Upon initial recognition of a liability, that cost is capitalized as part of the related long-lived asset and allocated to expense over the useful life of the asset.

Our asset retirement obligations primarily represent the present value of the estimated amount we will incur to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws.

The following is a reconciliation of our asset retirement obligations for the periods indicated:

	December 31,		
(in thousands)	**2015**	**2014**	**2013**
Asset retirement obligations at beginning of period	$ 36,755	$ 42,954	$ 61,864
Activity during the period:			
Liabilities incurred during the period	881	576	514
Revisions in estimated assumptions	3,215	—	1,268
Liabilities settled during the period	(293)	(33)	(187)
Adjustment to liability due to acquisitions	180	107	5,566
Adjustment to liability due to divestitures (1)	(1,367)	(9,539)	(28,585)
Accretion of discount	2,277	2,690	2,514
Asset retirement obligations at end of period	41,648	36,755	42,954
Less current portion	845	1,769	191
Long-term portion	$ 40,803	$ 34,986	$ 42,763

(1) For the year ended December 31, 2014, the adjustment to liability due to divestitures consisted primarily of $9.4 million from the sale of our interest in Compass. For the year ended December 31, 2013, the adjustment to liability due to divestitures consisted primarily of $28.3 million from the contribution of our certain conventional assets to Compass.

Our asset retirement obligations are determined using discounted cash flow methodologies based on inputs and assumptions developed by management. We do not have any assets that are legally restricted for purposes of settling asset retirement obligations.

Revenue recognition and gas imbalances

We use the sales method of accounting for oil and natural gas revenues. Under the sales method, revenues are recognized based on actual volumes of oil and natural gas sold to purchasers. Gas imbalances at December 31, 2015, 2014 and 2013 were not significant.

Gathering and transportation

We generally sell oil and natural gas under two types of agreements which are common in our industry. Both types of agreements include a transportation charge. One is a net-back arrangement, under which we sell oil or natural gas at the wellhead and collect a price, net of the transportation incurred by the purchaser. In this case, we record sales at the price received from the purchaser, net of the transportation costs. Under the other arrangement, we sell oil or natural gas at a specific delivery point, pay transportation to a third party and receive proceeds from the purchaser with no transportation deduction. In this case, we record the transportation cost as gathering and transportation expense. As such, our computed realized prices, before the impact of derivative financial instruments, include revenues which are reported under two separate bases. Gathering and transportation expenses totaled $99.3 million, $101.6 million and $100.6 million for the years ended December 31, 2015, 2014 and 2013, respectively.

Capitalization of internal costs

As part of our proved developed oil and natural gas properties, we capitalize a portion of salaries and related share-based compensation for employees who are directly involved in the acquisition, exploration, exploitation and development of oil and natural gas properties. During the years ended December 31, 2015, 2014 and 2013, we capitalized $10.6 million, $15.8 million and $18.2 million, respectively. The capitalized amounts include $3.4 million, $5.5 million and $7.3 million of share-based compensation for the years ended December 31, 2015, 2014 and 2013, respectively.

Overhead reimbursement fees

We have classified fees from overhead charges billed to working interest owners of $13.1 million, $13.5 million and $10.5 million for the years ended December 31, 2015, 2014 and 2013, respectively, as a reduction of general and administrative expenses in the accompanying Consolidated Statements of Operations. We classified our share of these charges as oil and natural gas production costs in the amount of $5.7 million, $6.4 million and $5.8 million for the years ended December 31, 2015, 2014 and 2013, respectively.

In addition, we have agreements with BG Group that allow us to bill each other certain personnel costs and related fees incurred on behalf of the joint ventures in the East Texas, North Louisiana and Appalachia regions. In connection with the formation of Compass, we entered into an agreement to perform certain operational, managerial, and administrative services. Compass reimbursed us for costs incurred in connection with the performance of these services based on an agreed upon service fee. As a result of the Compass sale, this agreement was terminated on October 31, 2014 and we entered into a customary transition services agreement pursuant to which EXCO provided certain transition services to Compass until April 2015. For the years ended December 31, 2015, 2014 and 2013, general and administrative expenses were reduced by $15.9 million, $24.7 million and $26.8 million, respectively, for recoveries of fees for our personnel and services provided to our joint ventures and other partners. These recoveries are net of fees charged to us by BG Group for their personnel and services.

Environmental costs

Environmental costs that relate to current operations are expensed as incurred. Remediation costs that relate to an existing condition caused by past operations are accrued when it is probable that those costs will be incurred and can be reasonably estimated based upon evaluations of currently available facts related to each site.

Income taxes

Income taxes are accounted for in accordance with FASB ASC 740, *Income Taxes* ("ASC 740"), under which deferred income taxes are recognized for the future tax effects of temporary differences between the financial statement carrying amounts and the tax basis of existing assets and liabilities using the enacted statutory tax rates in effect at year-end. The effect on deferred taxes for a change in tax rates is recognized in earnings in the period that includes the enactment date. A valuation allowance for deferred tax assets is recorded when it is more likely than not that the benefit from the deferred tax asset will not be realized.

Earnings per share

We account for earnings per share in accordance with FASB ASC 260-10, *Earnings Per Share* ("ASC 260-10"). ASC 260-10 requires companies to present two calculations of earnings per share ("EPS"); basic and diluted. Basic EPS is based on the weighted average number of common shares outstanding during the period, excluding stock options, restricted share units, restricted share awards and warrants. Diluted EPS is computed in the same manner as basic EPS after assuming the issuance of common shares for all potentially dilutive common share equivalents, which include stock options, restricted share units, restricted share awards and warrants, whether exercisable or not. Our diluted EPS for the year ended December 31, 2013 also included subscription rights which were the result of the rights offering of our common shares as discussed in "Note 15. Rights Offering and other equity transactions".

Equity-based compensation

Our equity-based compensation includes share-based compensation to employees which we account for in accordance with FASB ASC Topic 718, *Compensation-Stock Compensation* ("ASC 718") and equity-based compensation for warrants issued to ESAS which we account for in accordance with FASB ASC Topic 505-50, *Equity-Based Payments to Non-Employees* ("ASC 505-50").

ASC 718 requires all share-based payments to employees, including grants of employee stock options, restricted share units and restricted share awards, to be recognized in our Consolidated Statements of Operations based on their estimated fair values. We recognize expense on a straight-line basis over the vesting period of the option, restricted share unit or restricted share award. We capitalize part of our share-based compensation that is attributable to our acquisition, exploration, exploitation and development activities.

Our 2005 Amended and Restated Long-Term Incentive Plan ("2005 Incentive Plan") provides for the granting of options and other equity incentive awards of our common shares in accordance with terms within the agreements. New shares will be issued for any options exercised or awards granted. Under the 2005 Incentive Plan, we have only issued stock options, restricted share units and restricted share awards, although the plan allows for other share-based awards.

The measurement of the warrants is accounted for in accordance with ASC 505-50, which requires the warrants to be re-measured each interim reporting period until the completion of the services under the agreement and an adjustment is recorded in our Consolidated Statements of Operations included as equity-based compensation expense. See "Note. 11. Equity-based compensation" for additional information on the warrants issued to ESAS.

Recent accounting pronouncements

In April 2015, the FASB issued Accounting Standards Update ("ASU") No. 2015-03, Interest - Imputation of Interest (Subtopic 835-30): *Simplifying the Presentation of Debt Issuance Costs* ("ASU 2015-03"). ASU 2015-03 requires that debt issuance costs related to a recognized debt liability be presented in the balance sheet as a direct deduction from the carrying amount of that debt liability, consistent with debt discounts. Prior to the adoption of ASU 2015-03, we recognized debt issuance costs as assets on our balance sheet. The recognition and measurement guidance for debt issuance costs are not affected by ASU 2015-03. ASU 2015-03 is effective for annual and interim periods beginning after December 15, 2015 and early adoption is permitted. In August 2015, the FASB issued ASU 2015-15, Interest - Imputation of Interest (Subtopic 835-30): *Presentation and Subsequent Measurement of Debt Issuance Costs Associated with Line-of-Credit Arrangements* ("ASU 2015-15"). ASU 2015-15 clarifies that the SEC would not object to an entity deferring and presenting debt issuance costs related to a line-of-credit arrangement as an asset on the balance sheet. We adopted ASU 2015-03 and ASU 2015-15 in the fourth quarter of 2015 and applied the new guidance retrospectively to all periods presented. The adoption of ASU 2015-03 and ASU 2015-15 resulted in certain reclassifications of debt issuance costs on our balance sheets. See "Note 5. Debt" for additional information.

In September 2015, the FASB issued ASU No. 2015-16, Business Combinations (Topic 805): *Simplifying the Accounting for Measurement-Period Adjustments* ("ASU 2015-16"). ASU 2015-16 requires that an acquirer recognize adjustments to provisional amounts that are identified during the measurement period in the reporting period in which the adjustment amounts are determined. The amendments in this update require that the acquirer record, in the same period's financial statements, the effect on earnings of changes in depreciation, amortization, or other income effects, if any, as a result of the change to the provisional amounts, calculated as if the accounting had been completed at the acquisition date. The amendments in this update require an entity to present separately on the face of the income statement or disclose in the notes the portion of the amount recorded in current-period earnings by line item that would have been recorded in previous reporting periods if the adjustment to the provisional amounts had been recognized as of the acquisition date. ASU 2015-16 is effective for annual and interim periods beginning after December 15, 2015 and early adoption is permitted. We will apply this guidance to business combinations, when applicable, occurring after the effective date of ASU 2015-16.

In November 2015, the FASB issued ASU No. 2015-17, Income Taxes (Topic 740): *Balance Sheet Classification of Deferred Taxes* ("ASU 2015-17"). Prior to ASU 2015-17, GAAP required an entity to separate deferred income tax asset and liabilities into current and noncurrent amounts on the balance sheet. ASU 2015-17 requires that all deferred tax assets and liabilities, along with any related valuation allowance, be classified as noncurrent on the balance sheet. ASU 2015-17 is effective for annual and interim periods beginning after December 15, 2016 and early adoption is permitted. ASU 2015-17 may be applied either prospectively to all deferred tax assets and liabilities or retrospectively to all periods presented. We adopted ASU 2015-17 in 2015 and applied the guidance retrospectively which resulted in the reclassification of $35.9 million of net current deferred income tax liabilities to noncurrent as of December 31, 2014. The requirement that deferred tax liabilities and assets be offset and presented as a single amount was not affected by this amendment. See "Note 12. Income taxes" for further discussion and application of ASU 2015-17 to prior period information.

In February 2016, the FASB issued ASU No. 2016-02, Leases (Topic 842) ("ASU 2016-02"). The main difference between the current requirement under GAAP and ASU 2016-02 is the recognition of lease assets and lease liabilities by lessees for those leases classified as operating leases. ASU 2016-02 requires that a lessee recognize in the statement of financial position a liability to make lease payments (the lease liability) and a right-of-use asset representing its right to use the underlying asset for the lease term (other than leases that meet the definition of a short-term lease). The liability will be equal to the present value of lease payments. The asset will be based on the liability, subject to adjustment, such as for initial direct costs. For income statement purposes, the FASB retained a dual model, requiring leases to be classified as either operating or finance. Operating leases will result in straight-line expense (similar to current operating leases) while finance leases will result in a front-loaded expense pattern (similar to current capital leases). Classification will be based on criteria that are largely similar to those applied in current lease accounting. For lessors, the guidance modifies the classification criteria and the accounting for sales-type and direct financing leases. ASU 2016-02 is effective for annual and interim periods beginning after

December 15, 2018 and early adoption is permitted. ASU 2016-02 must be adopted using a modified retrospective transition, and provides for certain practical expedients. Transaction will require application of the new guidance at the beginning of the earliest comparative period presented. We are currently assessing the potential impact of ASU 2016-02 and expect it will have a material impact on our consolidated financial condition and results of operations upon adoption.

3. Acquisitions, divestitures and other significant events

2015 Acquisitions

Eagle Ford acquisition program

We have a participation agreement with a joint venture partner for the development of certain assets in the Eagle Ford shale ("Participation Agreement"). The Participation Agreement requires us to offer to purchase our joint venture partner's working interest in wells that have been on production for at least one year. The offers are made on a quarterly basis for a group of wells based on prices defined in the Participation Agreement, subject to specific well criteria and return hurdles.

We closed the first acquisition of our joint venture partner's interest in 3 gross (1.4 net) wells on March 11, 2015 for a total purchase price of $7.6 million. Our joint venture partner did not accept our second offer for 10 gross (5.2 net) wells in July 2015. The wells included in the offer did not meet the specified return hurdle in the Participation Agreement; therefore, our joint venture partner was not required to sell us the wells included in this offer.

During the fourth quarter of 2015, our Eagle Ford joint venture partner purported to accept our third quarterly offer under the Participation Agreement to purchase interests in 21 gross (10.3 net) wells for $42.7 million, subject to purchase price adjustments subsequent to the effective date of June 30, 2015. We notified our joint venture partner that we do not intend to close this acquisition and our joint venture partner filed a petition for injunctive relief and damages alleging that, among other things, we breached our obligation under the Participation Agreement. The court denied our joint venture partner’s motion for injunctive relief and their request to restrain us from disbursing proceeds from the production of the assets. We filed a counterclaim seeking a declaratory judgment that, among other things, we are not obligated to purchase the disputed wells as our partner's purported acceptance had not been received in a timely manner under the terms of the Participation Agreement. In addition, quarterly offers four and five are also now in dispute for various reasons. We cannot estimate or predict the outcome of the litigation with the our joint venture partner and we may not have sufficient funds or borrowing capacity under the EXCO Resources Credit Agreement to complete any acquisitions pursuant to the Participation Agreement or pay any damages for failure to complete a purchase that a court may determine, including the wells related to the claim by our joint venture partner. In the event we fail to purchase a group of wells that we are required to make an offer on, there are remedies available to our joint venture partner which allow them to reject our future offers, terminate the Participation Agreement, remove EXCO as the operator or pursue other legal remedies.

2014 Divestitures

Permian Basin transaction

On March 24, 2014, we closed a purchase and sale agreement with a private party for the sale of our interest in certain non-operated assets in the Permian Basin including producing wells and undeveloped acreage for approximately $68.2 million, after final purchase price adjustments. The effective date of the transaction was January 1, 2014. Proceeds from the sale were used to reduce indebtedness under our credit agreement ("EXCO Resources Credit Agreement").

Compass divestiture

On October 31, 2014, we closed the sale of our entire interest in Compass to Harbinger Group, Inc. ("HGI") for $118.8 million in cash. We used a portion of the proceeds to reduce indebtedness under the EXCO Resources Credit Agreement. Prior to the closing of the sale, we reported our 25.5% interest in Compass using proportional consolidation. Our consolidated assets and liabilities were reduced by our proportionate share of Compass's net assets of $31.4 million which included our proportionate share of the Compass's indebtedness of $83.2 million on October 31, 2014. The sale of our interest in Compass did not significantly alter the relationship between our capitalized costs and proved reserves and was accounted for as an adjustment of capitalized costs with no gain or loss recognized in accordance with Rule 4-10(c)(6)(i) of Regulation S-X. As a result, our capitalized costs were further reduced by $87.4 million. Following the closing, EXCO was no longer required to offer acquisition opportunities to Compass or any of its affiliates.

2013 Acquisitions, divestitures and other significant events

Compass

On February 14, 2013, we formed Compass. Pursuant to the agreements governing the transaction, we contributed our conventional shallow producing assets in East Texas and North Louisiana and our shallow Canyon Sand and other assets in the Permian Basin of West Texas to Compass, in exchange for net cash proceeds of $574.8 million, after final purchase price adjustments, and a 25.5% economic interest in the partnership. HGI's economic interest in Compass was 74.5% at its formation.

The contribution of oil and natural gas properties to Compass significantly altered the relationship between our capitalized costs and proved reserves. In accordance with full cost accounting rules, we recorded a gain of $186.4 million, net of a proportionate reduction in goodwill of $55.1 million, for the year ended December 31, 2013.

Immediately following the closing, Compass entered into an agreement to purchase the remaining shallow Cotton Valley assets in North Louisiana from an affiliate of BG Group for $130.7 million, after final purchase price adjustments. The assets acquired as a result of this transaction represented an incremental working interest in properties owned by Compass. The transaction closed on March 5, 2013 and was funded with borrowings from Compass's credit agreement.

Permian Basin transaction

On March 13, 2013, we closed a sale and joint development agreement with a private party for the sale of an undivided 50% of our interest in certain undeveloped acreage in the Permian Basin. The private party was designated as the operator under the joint development agreement. We received $37.9 million in cash, after final closing adjustments.

Haynesville and Eagle Ford Acquisitions

On July 2, 2013, we entered into definitive agreements with Chesapeake to acquire producing and undeveloped oil and natural gas assets in the Haynesville and Eagle Ford shale formations. We closed the acquisition of the Haynesville assets on July 12, 2013 for a purchase price of $281.1 million, after final purchase price adjustments. The acquisition included certain producing wells and non-producing oil, natural gas and mineral leases located in our core Haynesville shale operating area in Caddo Parish and DeSoto Parish, Louisiana. These properties included Chesapeake's non-operated interests in 170 wells operated by EXCO on approximately 5,500 net acres, and operated interests in 11 producing wells on approximately 4,000 net acres. BG Group elected not to exercise its preferential right to acquire a 50% interest in these assets.

We closed the acquisition of the Eagle Ford assets on July 31, 2013 for a purchase price of $661.8 million, after final purchase price adjustments. The acquisition included certain producing wells and non-producing oil, natural gas and mineral leases in the Eagle Ford shale in the counties of Zavala, Dimmit and Frio in South Texas. These properties initially included operated interests in 120 wells on approximately 53,500 net acres. In connection with the acquisition of the Eagle Ford assets, we entered into a farm-out agreement with Chesapeake covering acreage adjacent to the acquired properties. Pursuant to the terms of the farm-out agreement, Chesapeake retains an overriding royalty interest in wells drilled on acreage covered by the farm-out agreement, with an option to convert the overriding royalty interest to a working interest at payout of the well.

We accounted for the acquisitions in accordance with FASB ASC Topic 805, *Business Combinations*. The following table presents a summary of the fair value of assets acquired and liabilities assumed as part of the Haynesville and Eagle Ford acquisitions based on the final settlement statements as of July 12, 2013 and July 31, 2013, respectively:

Purchase Price Allocation (in thousands):	**Haynesville Acquired Properties**	**Eagle Ford Acquired Properties**
Assets acquired:		
Unproved oil and natural gas properties	$ 2,319	$ 227,869
Proved developed and undeveloped oil and natural gas properties	282,918	437,616
Liabilities assumed:		
Accounts payable and accrued liabilities	—	(580)
Revenues and royalties payable	(3,526)	—
Asset retirement obligations	(610)	(3,060)
Total purchase price	$ 281,101	$ 661,845

We performed a valuation of the assets acquired and liabilities assumed as of the respective acquisition dates. A summary of the key inputs are as follows:

Oil and Natural Gas Properties - The fair value allocated to proved and unproved oil and natural gas properties was $285.2 million for the Haynesville assets and $665.5 million for the Eagle Ford assets. The fair value of oil and natural gas properties was determined based on a discounted cash flow model of the estimated reserves. The estimated quantities of reserves utilized assumptions based on our internal geological, engineering and financial data. We utilized NYMEX forward strip prices to value the reserves, then applied various discount rates depending on the classification of reserves and other risk characteristics.

Asset Retirement Obligations - The fair value allocated to asset retirement obligations was $0.6 million for the Haynesville assets and $3.1 million for the Eagle Ford assets. These asset retirement obligations represent the present value of the estimated amount to be incurred to plug, abandon and remediate our proved producing properties at the end of their productive lives, in accordance with applicable state laws. The fair value was determined based on a discounted cash flow model, which included assumptions of the estimated current abandonment costs, discount rate, inflation rate, and timing associated with the incurrence of these costs.

Revenues and royalties payable and accounts payable and accrued liabilities - The fair value was equivalent to the carrying amount because of the short-term nature of these liabilities.

KKR Participation Agreement

In connection with closing the acquisition of the Eagle Ford assets, we entered into a Participation Agreement with KKR and sold an undivided 50% interest in the undeveloped acreage we acquired for approximately $130.9 million, after final purchase price adjustments. Proceeds from the sale of properties under the Participation Agreement were used to reduce outstanding borrowings under the EXCO Resources Credit Agreement.

Under the Participation Agreement, EXCO is required to offer to purchase our joint venture partner's working interest in wells drilled that have been on production for approximately one year. These offers will be made on a quarterly basis for groups of wells based on a price defined in the Participation Agreement, subject to specific well criteria and return hurdles. Our joint venture partner has the right to participate in certain wells drilled in the Eagle Ford shale outside of the core area, as defined under the Participation Agreement, however these wells are not included as part of the acquisition program. If our joint venture partner elects to participate in certain wells outside of our core area, we will share equally in the working interest of the well.

TGGT transaction

On November 15, 2013, EXCO and BG Group closed the conveyance of 100% of the equity interests in TGGT to Azure Midstream Holdings LLC ("Azure"). We received $240.2 million in net cash proceeds at the closing and an equity interest in Azure of approximately 4%. We recorded an equity investment of $13.4 million, net of a discount for a control premium, in Azure which is accounted for under the cost method of accounting. Investments accounted for by the cost method are tested for impairment if an impairment indicator is present. During the year ended December 31, 2015, we recorded an other than temporary impairment of $2.9 million to our investment in Azure. See "Note 6. Fair value measurements" for further discussion.

At the closing of the agreement, EXCO and BG Group agreed to deliver to Azure's gathering systems an aggregate minimum volume commitment of 600,000 Mmbtu/day of natural gas production from the Holly and Shelby fields over a five year period. The minimum volume commitment may be satisfied with (i) production of EXCO, BG Group and each of their respective affiliates, (ii) production of joint venture partners of either EXCO, BG Group or their affiliates, and (iii) production of non-operating working interest owners to the extent EXCO, BG Group, and each of their respective affiliates or its joint venture partner controls such production. If there is a shortfall to the minimum volume commitment in any year, then EXCO and BG Group are severally responsible for paying to Azure a shortfall payment in an amount equal to the amount of the shortfall (calculated on an annualized basis) times $0.40 per Mmbtu. EXCO and BG Group are entitled to credit 25% of any production volumes delivered in excess of the minimum volume commitment during any year to the subsequent year.

We used all of the cash proceeds from the sale of TGGT to reduce outstanding borrowings under the EXCO Resources Credit Agreement. We recorded an other than temporary impairment of $86.8 million to our investment in TGGT during 2013 as a result of the carrying value exceeding the fair value.

4. Derivative financial instruments

Our primary objective in entering into derivative financial instruments is to manage our exposure to commodity price fluctuations, protect our returns on investments and achieve a more predictable cash flow from operations. These transactions limit exposure to declines in commodity prices, but also limit the benefits we would realize if commodity prices increase. When prices for oil and natural gas are volatile, a significant portion of the effect of our derivative financial instrument management activities consists of non-cash income or expense due to changes in the fair value of our derivative financial instruments. Cash losses or gains only arise from payments made or received on monthly settlements of contracts or if we terminate a contract prior to its expiration. We do not designate our derivative financial instruments as hedging instruments for financial accounting purposes and, as a result, we recognize the change in the respective instruments' fair value in earnings.

The table below outlines the classification of our derivative financial instruments on our Consolidated Balance Sheets and their financial impact on our Consolidated Statements of Operations.

Fair Value of Derivative Financial Instruments

(in thousands)	December 31, 2015	December 31, 2014
Derivative financial instruments - Current assets	$ 39,499	$ 97,278
Derivative financial instruments - Long-term assets	6,109	2,138
Derivative financial instruments - Current liabilities	(16)	(892)
Derivative financial instruments - Long-term liabilities	—	—
Net derivative financial instruments	$ 45,592	$ 98,524

The Effect of Derivative Financial Instruments

	Year Ended December 31,		
(in thousands)	2015	2014	2013
Gain (loss) on derivative financial instruments	$ 75,869	$ 87,665	$ (320)

Settlements in the normal course of maturities of our derivative financial instrument contracts result in cash receipts from, or cash disbursements to, our derivative contract counterparties. Changes in the fair value of our derivative financial instrument contracts, which includes both cash settlements and non-cash changes in fair value, are included in earnings with a corresponding increase or decrease in the Consolidated Balance Sheets fair value amounts.

At December 31, 2015, our oil and natural gas derivative instruments were comprised of swap contracts which allow us to receive a fixed price and pay a floating market price to the counterparty for the hedged commodity.

In the fourth quarter of 2015, we settled our remaining basis swap contracts and our remaining call option contracts expired. Basis swaps allowed us to receive a fixed price differential between market indices for oil prices based on the delivery point. Our oil basis swaps typically had a positive differential to NYMEX WTI oil prices. Call options gave our trading counterparties the right, but not the obligation, to buy an agreed quantity of oil or natural gas from us at a certain time and price in the future. At the time of settlement, if the market price exceeded the fixed price of the call option, we paid the counterparty the excess. If the market price settled below the fixed price of the call option, no payment was due from either party. In exchange for selling this option, we received upfront proceeds which we used to obtain a higher fixed price on our swaps. These transactions were conducted contemporaneously with a single counterparty and resulted in a net cashless transaction.

A three-way collar is a combination of options including a sold call, a purchased put and a sold put. In the fourth quarter of 2015, we converted all of our remaining 2016 three-way collars to fixed-price swaps covering 10,980 Bbtu of natural gas at an average price of $2.78 per Mmbtu. These transactions were conducted contemporaneously with the same counterparties and resulted in a net cashless transaction.

We place our derivative financial instruments with the financial institutions that are lenders under our respective credit agreements that we believe have high quality credit ratings. To mitigate our risk of loss due to default, we have entered into master netting agreements with counterparties to our derivative financial instruments that allow us to offset our asset position with our liability position in the event of a default by the counterparty.

The following table presents the volumes and fair value of our oil and natural gas derivative financial instruments as of December 31, 2015:

(dollars in thousands, except prices)	Volume Bbtu/ Mbbl	Weighted average strike price per Mmbtu/Bbl	Fair value at December 31, 2015
Natural gas:			
Swaps:			
2016	34,770	$ 3.09	$ 20,894
2017	10,950	3.28	5,279
2018	3,650	3.15	830
Total natural gas			$ 27,003
Oil:			
Swaps:			
2016	915	$ 61.89	$ 18,589
Total oil			$ 18,589
Total oil and natural gas derivative financial instruments			$ 45,592

At December 31, 2014, we had outstanding swap, call option and three-way collar contracts covering 42,888 Bbtu, 20,075 Bbtu and 38,355 Bbtu, respectively, of natural gas and we had outstanding swap, basis swap and call option contracts covering 1,095 Mbbls, 91 Mbbls and 365 Mbbls, respectively, of oil.

At December 31, 2015, the average forward NYMEX WTI oil price per Bbl for the calendar year 2016 was $40.97 and the average forward NYMEX HH natural gas prices per Mmbtu for the calendar years 2016, 2017 and 2018 were $2.50, $2.79 and $2.91, respectively.

Our derivative financial instruments covered approximately 68% and 69% of production volumes for the years ended December 31, 2015 and 2014.

5. Debt

The carrying value of our total debt is summarized as follows:

(in thousands)	December 31, 2015	December 31, 2014
EXCO Resources Credit Agreement	$ 67,492	$ 202,492
Exchange Term Loan	641,172	—
Fairfax Term Loan	300,000	—
2018 Notes	158,015	750,000
Unamortized discount on 2018 Notes	(932)	(5,957)
2022 Notes	222,826	500,000
Deferred financing costs, net	(18,294)	(16,019)
Total debt, net	1,370,279	1,430,516
Less amounts due within one year	50,000	—
Total debt due after one year	$ 1,320,279	$ 1,430,516

(in thousands)	December 31, 2015 Carrying value	Deferred reduction in carrying value	Unamortized discount/ deferred financing costs	Principal balance
EXCO Resources Credit Agreement	$ 67,492	$ —	$ —	$ 67,492
Exchange Term Loan	641,172	(241,172)	—	400,000
Fairfax Term Loan	300,000	—	—	300,000
2018 Notes	157,083	—	932	158,015
2022 Notes	222,826	—	—	222,826
Deferred financing costs, net	(18,294)	—	18,294	—
Total debt	$ 1,370,279	$ (241,172)	$ 19,226	$ 1,148,333

Terms and conditions of each of these debt obligations are discussed below.

Recent transactions

On October 26, 2015, we closed a 12.5% senior secured second lien term loan with certain affiliates of Fairfax Financial Holdings Limited ("Fairfax") in the aggregate principal amount $300.0 million (“Fairfax Term Loan”). We used the proceeds from the Fairfax Term Loan to repay outstanding indebtedness under the EXCO Resources Credit Agreement. We also closed a 12.5% senior secured second lien term loan with certain unsecured noteholders in the aggregate principal amount of $291.3 million on October 26, 2015 and $108.7 million on November 4, 2015 (“Exchange Term Loan,” and together with the Fairfax Term Loan, “Second Lien Term Loans”). The proceeds from the Exchange Term Loan were used to repurchase a portion of the outstanding 7.5% senior unsecured notes due September 15, 2018 ("2018 Notes") and 8.5% senior unsecured notes due April 15, 2022 ("2022 Notes") in exchange for the holders of such notes agreeing to act as lenders in connection with the Exchange Term Loan. The exchange was accounted for as a troubled debt restructuring pursuant to FASB ASC 470-60, *Troubled Debt Restructuring by Debtors*. We have determined that the future undiscounted cash flows from the Exchange Term Loan through its maturity were less than the carrying amounts of the retired 2018 Notes and 2022 Notes. As a result, we have adjusted our carrying amount of the Exchange Term Loan to equal the total future cash payments, including interest and principal, which resulted in a net gain on the restructuring of debt of $165.1 million included in Gain on restructuring and extinguishment of debt in our Consolidated Statements of Operations. Subsequently, all cash payments under the terms of the Exchange Term Loan, whether designated as interest or as principal amount, will reduce the carrying amount and no interest expense will be recognized. As such, our reported interest expense will be less than the contractual payments throughout the term of the Exchange Term Loan.

In the fourth quarter of 2015, we repurchased $40.8 million in principal of the 2018 Notes through open market purchases with $12.0 million in cash. The open market repurchases resulted in a $28.2 million net gain on extinguishment of debt which is included in Gain on restructuring and extinguishment of debt in our Consolidated Statements of Operations. The net gain included an acceleration of the related deferred financing costs and notes discount. Additionally, in February 2016, we repurchased $9.5 million and $39.9 million in principal of the 2018 Notes and 2022 Notes, respectively, with $6.7 million in cash. See further discussion of the Second Lien Term Loans and the 2018 Notes and 2022 Notes repurchases below.

EXCO Resources Credit Agreement

At December 31, 2015, the EXCO Resources Credit Agreement had $67.5 million of outstanding indebtedness, $375.0 million of available borrowing base and $300.9 million of unused borrowing base, net of letters of credit. The maturity date of the EXCO Resources Credit Agreement is July 31, 2018. The interest rate grid for the revolving commitment under the EXCO Resources Credit Agreement ranges from LIBOR plus 225 bps to 325 bps (or alternate base rate ("ABR") plus 125 bps to 225 bps), depending on our borrowing base usage. On December 31, 2015, our interest rate was approximately 3.3% on the revolving commitment.

As of December 31, 2015, we were in compliance with the financial covenants (each as defined in the EXCO Resources Credit Agreement), which required that we:

- maintain a consolidated current ratio of at least 1.0 to 1.0 as of the end of any fiscal quarter;
- maintain a ratio of consolidated EBITDAX to consolidated interest expense ("Interest Coverage Ratio") of at least 1.25 to 1.0 as of the end of any fiscal quarter. The consolidated interest expense utilized in the Interest Coverage

Ratio is calculated in accordance with GAAP; therefore, this excludes cash payments under the terms of the Exchange Term Loan, whether designated as interest or as face amount, that reduce the carrying amount and are not recognized as interest expense; and
- not permit our ratio of senior secured indebtedness to consolidated EBITDAX ("Senior Secured Indebtedness Ratio"), to be greater than 2.5 to 1.0 as of the end of any fiscal quarter. Senior secured indebtedness utilized in the Senior Secured Indebtedness Ratio excludes the Second Lien Term Loans and any other indebtedness subordinated to the EXCO Resources Credit Agreement.

On October 19, 2015, we entered into an amendment to the EXCO Resources Credit Agreement that, among other things, reduced the borrowing base from $600.0 million to $375.0 million, effective upon the issuance of the Second Lien Term Loans. The amendment also amended the EXCO Resources Credit Agreement such that, upon our incurrence of second or third lien debt, including the Second Lien Term Loans, the revolving commitments under the EXCO Resources Credit Agreement were automatically reduced to $375.0 million. The Second Lien Term Loans limit the issuance of priority lien indebtedness to a maximum of $500.0 million without prior written consent of the administrative agent of the Fairfax Term Loan. In addition, the amendment provides that, with respect to the issuance of any second or third lien debt following the incurrence of the Second Lien Loans, if the issuance of such debt causes the aggregate principal amount of our second or third lien debt to exceed $900.0 million, the borrowing base will be further reduced. The requirement to comply with the leverage ratio maintenance covenant (as defined in the EXCO Resources Credit Agreement) was terminated as a result of the amendment.

The borrowing base under the EXCO Resources Credit Agreement remains subject to semi-annual review and redetermination by the lenders pursuant to the terms of the EXCO Resources Credit Agreement, and the next scheduled redetermination of the borrowing base is set to occur in March 2016.

The majority of our subsidiaries are guarantors under the EXCO Resources Credit Agreement. The EXCO Resources Credit Agreement permits investments, loans and advances to the unrestricted subsidiaries related to our joint ventures with certain limitations, and allows us to repurchase up to $200.0 million of our common shares, of which $7.6 million has been repurchased to date. The 16,621 shares and 38,821 shares repurchased in 2015 and 2014, respectively, were tendered by employees to satisfy minimum tax withholding amounts for restricted share awards.

Borrowings under the EXCO Resources Credit Agreement are collateralized by first lien mortgages providing a security interest of not less than 80% of the engineered value, as defined in the agreement, in our oil and natural gas properties covered by the borrowing base. We are permitted to have derivative financial instruments covering no more than 100% of forecasted production from total Proved Reserves, as defined in the agreement, for any month during the first two years of the forthcoming five-year period, 90% of forecasted production from total Proved Reserves for any month during the third year of the forthcoming five-year period and 85% of forecasted production from total Proved Reserves for any month during the fourth and fifth years of the forthcoming five-year period.

Second Lien Term Loans

Each of the Second Lien Term Loans matures on October 26, 2020 and bears interest at a rate of 12.5% per annum, which is payable on the last day in each calendar quarter. The Second Lien Term Loans are guaranteed by substantially all of EXCO's subsidiaries, with the exception of certain non-guarantor subsidiaries and our jointly-held equity investments with BG Group, and are secured by second-priority liens on substantially all of EXCO's assets securing the indebtedness under the EXCO Resources Credit Agreement. The Second Lien Term Loans rank (i) junior to the debt under the EXCO Resources Credit Agreement and any other priority lien obligations, (ii) pari passu to one another and (iii) effectively senior to all of our existing and future unsecured senior indebtedness, including the 2018 Notes and the 2022 Notes, to the extent of the collateral.

The agreements governing the Second Lien Term Loans contain covenants that, subject to certain exceptions, limit our ability and the ability of our restricted subsidiaries to, among other things:

- pay dividends or make other distributions or redeem or repurchase our common shares;
- prepay, redeem or repurchase certain debt;
- enter into agreements restricting the subsidiary guarantors' ability to pay dividends to us or another subsidiary guarantor, make loans or advances to us or transfer assets to us;
- engage in asset sales or substantially alter the business that the we conduct;
- enter into transactions with affiliates;
- consolidate, merge or dispose of assets;
- incur liens; and
- enter into sale/leaseback transactions.

In addition, the term loan agreement governing the Exchange Term Loan prohibits us from incurring, among other things and subject to certain exceptions:

- debt under the EXCO Resources Credit Agreement in excess of the greatest of (i) $375.0 million plus an amount equal to six and two-thirds percent of the aggregate principal amount of our outstanding indebtedness under the EXCO Resources Credit Agreement for over-advances to protect collateral, (ii) the borrowing base under the EXCO Resources Credit Agreement or (iii) 30% of modified adjusted consolidated net tangible assets (as defined in the agreement);
- second lien debt in excess of $700.0 million; and
- unsecured debt where on the date of such incurrence or after giving effect to such incurrence, our consolidated coverage ratio (as defined in the agreement) is or would be less than 2.25 to 1.0.

The term loan agreement governing the Fairfax Term Loan prohibits us from incurring, among other things and subject to certain exceptions:

- debt under the EXCO Resources Credit Agreement in excess of $375.0 million plus an amount equal to six and two-thirds percent of the aggregate principal amount of our outstanding indebtedness under the EXCO Resources Credit Agreement for over-advances to protect collateral, provided that such indebtedness may not exceed $500.0 million, unless we obtain consent from the administrative agent;
- second lien debt, other than the Exchange Term Loan, in excess of (i) $400.0 million prior to December 31, 2015 and (ii) an amount to be agreed upon with the administrative agent after December 31, 2015;
- junior lien debt, unless such debt is being used to refinance the 2018 Notes or the 2022 Notes or the terms and conditions of such junior lien debt are approved by the administrative agent; and
- unsecured debt, unless we obtain consent from the administrative agent.

In connection with the Second Lien Term Loans, on October 26, 2015, EXCO entered into an intercreditor agreement governing the relationship between EXCO's lenders and the holders of any other lien obligations that EXCO may issue in the future and a collateral trust agreement governing the administration and maintenance of the collateral securing the Second Lien Term Loans.

2018 Notes

The 2018 Notes are guaranteed on a senior unsecured basis by a majority of EXCO's subsidiaries, with the exception of certain non-guarantor subsidiaries and our jointly-held equity investments with BG Group. Our equity investments with BG Group, other than OPCO, have been designated as unrestricted subsidiaries under the indenture governing the 2018 Notes.

In the fourth quarter of 2015, EXCO repurchased an aggregate $551.2 million of the 2018 Notes in exchange for certain holders of the 2018 Notes to act as lenders under the Exchange Term Loan. Additionally, we repurchased $40.8 million in principal amount of the 2018 Notes with $12.0 million in cash through open market purchases in the fourth quarter of 2015. Additionally, in February 2016, we repurchased $9.5 million in principal amount of the 2018 Notes with $2.2 million in cash. The 2018 Notes repurchased will be canceled by the trustee following customary settlement procedures. As a result of the repurchases, the aggregate principal amount of outstanding 2018 Notes was reduced to $148.5 million as of February 25, 2016. Interest accrues at 7.5% and is payable semi-annually in arrears on March 15th and September 15th of each year.

The indenture governing the 2018 Notes contains covenants, which may limit our ability and the ability of our restricted subsidiaries to:

- incur or guarantee additional debt and issue certain types of preferred shares;
- pay dividends on our capital stock or redeem, repurchase or retire our capital stock or subordinated debt;
- make certain investments;
- create liens on our assets;
- enter into sale/leaseback transactions;
- create restrictions on the ability of our restricted subsidiaries to pay dividends or make other payments to us;
- engage in transactions with our affiliates;
- transfer or issue shares of stock of subsidiaries;
- transfer or sell assets; and
- consolidate, merge or transfer all or substantially all of our assets and the assets of our subsidiaries.

On November 25, 2015, the Company obtained the requisite consents to amend the indenture governing the 2018 Notes. Following the receipt of the requisite consents, EXCO entered into a supplemental indenture which, among other things, eliminated the reduction in the amount of secured indebtedness permitted under the EXCO Resources Credit Agreement upon principal payments which results in a permanent reduction in borrowing capacity of EXCO. As a result, the amount of secured indebtedness permitted under the EXCO Resources Credit Agreement cannot exceed the greater of $1.2 billion or a calculation based on the value of our assets.

2022 Notes

The 2022 Notes were issued at 100.0% of the principal amount and bear interest at a rate of 8.5% per annum, payable in arrears on April 15 and October 15 of each year. On November 4, 2015, EXCO completed a repurchase of $277.2 million of the 2022 Notes in exchange for certain holders of the 2022 Notes to act as lenders under the Exchange Term Loan. Additionally, in February 2016, we repurchased $39.9 million in principal amount of the 2022 Notes with $4.5 million in cash. The 2022 Notes repurchased will be canceled by the trustee following customary settlement procedures. As a result of the note repurchase, the aggregate principal amount of outstanding 2022 Notes was reduced to $182.9 million as of February 25, 2016.

The 2022 Notes rank equally in right of payment to any existing and future senior unsecured indebtedness of the Company (including the 2018 Notes) and are guaranteed on a senior unsecured basis by EXCO's consolidated subsidiaries that are guarantors of the indebtedness under the EXCO Resources Credit Agreement. The 2022 Notes were issued under the same base indenture governing the 2018 Notes and the supplemental indenture governing the 2022 Notes contains similar covenants to those in the supplemental indenture governing the 2018 Notes.

The foregoing descriptions are not complete and are qualified in their entirety by the EXCO Resources Credit Agreement, the indenture governing the 2018 Notes and 2022 Notes and the agreements governing the Second Lien Term Loans.

Deferred Financing Costs

In the fourth quarter of 2015, we adopted ASU 2015-03 and ASU 2015-15 and reclassified deferred financing costs related to the 2018 Notes, 2022 Notes and Second Lien Term Loans from an asset to a contra-liability account on our Consolidated Balance Sheets and reflected the change retrospectively in the table above. Deferred financing costs related to the EXCO Resources Credit Agreement will be classified as an asset as allowed by ASU 2015-15.

Liquidity and covenants

While we believe our existing capital resources, including our cash flow from operations and borrowing capacity under the EXCO Resources Credit Agreement, are sufficient to conduct our operations through 2016 and into 2017, there are certain risks arising from depressed oil and natural gas prices and declines in production volumes that could impact our liquidity and ability to meet debt covenants in future periods. Our ability to maintain compliance with our debt covenants may be negatively impacted when oil and/or natural gas prices remain depressed for an extended period of time. Reductions in our borrowing capacity as a result of a redetermination to our borrowing base could have an impact on our capital resources and liquidity. The borrowing base redetermination process considers assumptions related to future commodity prices; therefore, our borrowing capacity could be negatively impacted by further declines in oil and natural gas prices. Accordingly, our ability to effectively execute our corporate strategies and manage our operating, general and administrative expenses and capital expenditure programs is critical to our financial condition, liquidity and our results of operations.

If we are not able to meet our debt covenants in future periods, or if our borrowing base is significantly reduced, we may be required but unable to refinance all or part of our existing debt, sell assets, borrow more money or raise equity on terms acceptable to us, if at all, and may be required to surrender assets pursuant to the security provisions of the EXCO Resources Credit Agreement and the Second Lien Term Loans. Further, failing to comply with the financial and other restrictive covenants in the EXCO Resources Credit Agreement, 2018 Notes, 2022 Notes and the Second Lien Term Loans could result in an event of default, which could adversely affect our business, financial condition and results of operations.

6. Fair value measurements

We value our derivatives and other financial instruments according to FASB ASC 820, *Fair Value Measurements and Disclosures*, which defines fair value as the exchange price that would be received for an asset or paid to transfer a liability ("exit price") in the principal or most advantageous market for the asset or liability in an orderly transaction between market participants on the measurement date.

We categorize the inputs used in measuring fair value into a three-tier fair value hierarchy. These tiers include:

Level 1 – Observable inputs, such as quoted market prices in active markets, for substantially identical assets and liabilities.

Level 2 – Observable inputs other than quoted prices within *Level 1* for similar assets and liabilities. These include quoted prices in markets that are not active or other inputs that are observable or can be corroborated by observable market data. If the asset or liability has a specified or contractual term, the input must be observable for substantially the full term of the asset or liability.

Level 3 – Unobservable inputs that are supported by little or no market activity, generally requiring development of fair value assumptions by management.

Fair value of derivative financial instruments

The fair value of our derivative financial instruments may be different from the settlement value based on company-specific inputs, such as credit rating, futures markets and forward curves, and readily available buyers or sellers. During the years ended December 31, 2015 and 2014 there were no changes in the fair value level classifications. The following table presents a summary of the estimated fair value of our derivative financial instruments as of December 31, 2015 and 2014.

	December 31, 2015			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
Oil and natural gas derivative financial instruments	$ —	$ 45,592	$ —	$ 45,592

	December 31, 2014			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
Oil and natural gas derivative financial instruments	$ —	$ 98,524	$ —	$ 98,524

We evaluate derivative assets and liabilities in accordance with master netting agreements with the derivative counterparties, but report them on a gross basis on our Consolidated Balance Sheets. Net derivative asset values are determined primarily by quoted futures prices and utilization of the counterparties' credit-adjusted risk-free rate curves and net derivative liabilities are determined by utilization of our credit-adjusted risk-free rate curve. The credit-adjusted risk-free rates of our counterparties are based on an independent market-quoted credit default swap rate curve for the counterparties' debt plus the London Interbank Offered Rate ("LIBOR") curve as of the end of the reporting period. Our credit-adjusted risk-free rate is based on the blended rate of independent market-quoted credit default swap rate curves for companies that have the same credit rating as us plus the LIBOR curve as of the end of the reporting period.

The valuation of our commodity price derivatives, represented by oil and natural gas swaps, basis swaps, call option and three-way collar contracts, is discussed below.

Oil derivatives. Our oil derivatives historically consisted of swap, basis swap and call option contracts for notional Bbls of oil at fixed (in the case of swap and basis swap contracts) or interval (in the case of call option contracts) NYMEX oil index prices. The asset and liability values attributable to our oil derivatives as of the end of the reporting period are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for oil index prices, (iii) the applicable credit-adjusted risk-free rate curve, as described above, and (iv) the implied rate of volatility inherent in the call option contracts. The implied rates of volatility were determined based on average NYMEX oil index prices.

Natural gas derivatives. Our natural gas derivatives historically consisted of swap, three-way collar and call option contracts for notional Mmbtus of natural gas at posted price indexes, including NYMEX HH swap and option contracts. The asset and liability values attributable to our natural gas derivatives as of the end of the reporting period are based on (i) the contracted notional volumes, (ii) independent active NYMEX futures price quotes for HH for natural gas swaps, (iii) the applicable credit-adjusted risk-free rate curve, as described above and (iv) the implied rate of volatility inherent in the option contracts. The implied rates of volatility were determined based on average HH natural gas prices.

See further details on the fair value of our derivative financial instruments in "Note 4. Derivative financial instruments".

Fair value of other financial instruments

Our financial instruments include cash and cash equivalents, accounts receivable and payable and accrued liabilities. The carrying amount of these instruments approximates fair value because of their short-term nature.

The carrying values of our borrowings under the revolving commitment of the EXCO Resources Credit Agreement approximates fair value, as it is subject to short-term floating interest rates that approximate the rates available to us for those periods.

The estimated fair values of our 2018 Notes, 2022 Notes, Exchange Term Loan and Fairfax Term Loan are presented below. The estimated fair values of the 2018 Notes and 2022 Notes have been calculated based on quoted prices in active markets. The estimated fair values of the Exchange Term Loan and the Fairfax Term Loan have been calculated based on quoted prices obtained from third-party pricing sources and are classified as Level 2.

	December 31, 2015			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
2018 Notes	$ 43,170	$ —	$ —	$ 43,170
2022 Notes	48,376	—	—	48,376
Exchange Term Loan	—	278,000	—	278,000
Fairfax Term Loan	—	208,500	—	208,500

	December 31, 2014			
(in thousands)	**Level 1**	**Level 2**	**Level 3**	**Total**
2018 Notes	$ 558,750	$ —	$ —	$ 558,750
2022 Notes	373,500	—	—	373,500

As of February 25, 2016, the estimated fair values of our 2018 Notes, 2022 Notes, Exchange Term Loan and Fairfax Term Loan decreased to $25.2 million, $37.6 million, $178.0 million and $133.5 million, respectively. The estimated fair values were calculated based on the aggregate outstanding principal balance for each respective instrument at December 31, 2015.

Other fair value measurements

As discussed in "Note 2. Summary of significant accounting policies", we assess our unproved oil and natural gas properties for potential impairment due to an other than temporary trend that would negatively impact the fair value. The continued depressed oil and natural gas prices as well as longer-term commodity price outlooks provided indications of possible impairment. During the year ended December 31, 2015, we impaired approximately $88.1 million of unproved properties to reduce the carrying value to the fair value. These impairment charges were transferred to the depletable portion of the full cost pool. We calculated the estimated fair value of our unproved properties based on the average cost per undeveloped acre or the discounted cash flow models from our internally generated oil and natural gas reserves as of December 31, 2015. The pricing utilized in the discounted cash flow models was based on NYMEX futures, adjusted for basis differentials. Our oil and natural gas properties were further discounted based on the classification of the underlying reserves and management's assessment of recoverability. The fair value measurements utilized include significant unobservable inputs that are considered to be Level 3 within the fair value hierarchy. These unobservable inputs include management's estimates of reserve quantities, commodity prices, operating costs, development costs, discount factors and other risk factors applied to the future cash flows. The average cost per undeveloped acre was based on recent comparable market transactions in each region.

We impaired $11.0 million of our equity method investment in a midstream company in the Appalachia region. The impairment was primarily a result of limited development activity in the region, which is expected to reduce the future cash flows associated with the gathering and transportation revenues of the entity. In addition, we impaired $2.9 million of our investment in a midstream company in the East Texas and North Louisiana regions that we account for under the cost method of accounting. Both of the impairments were recorded to reduce the carrying value to the fair value and are considered to be Level 3 within the fair value hierarchy. The estimated fair value of our equity method investment was determined based on trading metrics for peer companies and the discounted cash flow models from our internally generated oil and natural gas reserves for the related properties as of December 31, 2015. The estimated fair value of our cost method investment was determined based on trading metrics for peer companies.

7. Environmental regulation

Various federal, state and local laws and regulations covering discharge of materials into the environment, or otherwise relating to the protection of the environment, may affect our operations and the costs of our oil and natural gas exploitation, development and production operations. We do not anticipate that we will be required in the foreseeable future to expend amounts material in relation to the financial statements taken as a whole by reason of environmental laws and regulations. Because these laws and regulations are constantly being changed, we are unable to predict the conditions and other factors over which we do not exercise control that may give rise to environmental liabilities affecting us.

8. Commitments and contingencies

The following table presents our future minimum obligations under our commercial commitments as of December 31, 2015. The commitments do not include those of our equity method investments.

(in thousands)	Gathering and firm transportation services	Other fixed commitments	Drilling contracts	Operating leases and other	Total
2016	$ 120,414	$ 13,253	$ 14,997	$ 5,456	$ 154,120
2017	120,085	5,443	7,284	4,228	137,040
2018	116,365	3,210	—	3,240	122,815
2019	76,285	2,403	—	3,053	81,741
2020	48,148	1,932	—	1,560	51,640
Thereafter	135,943	1,599	—	72	137,614
Total	$ 617,240	$ 27,840	$ 22,281	$ 17,609	$ 684,970

We have entered into firm transportation and gathering agreements with pipeline companies to facilitate sales from our East Texas and North Louisiana production. Gathering and firm transportation services presented in the tables within this footnote represent our gross commitments under these contracts and a portion of these costs will be incurred by working interest and other owners. We report these costs as gathering and transportation expenses or as a reduction in total sales price received from the purchaser. In addition, our variable rate firm transportation contracts do not have a minimum volume commitment and are not included in the table above. As such, our gathering and firm transportation services presented in the table above may not be representative of the amounts reported as gathering and transportation expenses in our Consolidated Financial Statements.

We lease our offices and certain equipment. Our rental expenses were approximately $3.4 million, $5.1 million and $5.9 million for the years ended December 31, 2015, 2014 and 2013, respectively. We have also entered into drilling rig contracts primarily to develop our assets in the East Texas and North Louisiana regions. The actual drilling costs under these contracts will be incurred by working interest owners in the development of the related properties. These contracts are short-term in nature and are dependent on our planned drilling program.

Our other fixed commitments primarily consist of completion service contracts and marketing contracts in which we are obligated to pay the buyer a fee if we fail to deliver minimum quantities of natural gas.

At December 31, 2015, our firm transportation and gathering agreements covered the following gross volumes of natural gas:

(in Bcf)	Firm transportation services	Gathering services
2016	270	110
2017	269	110
2018	269	100
2019	269	—
2020	177	—
Thereafter	596	—
Total	1,850	320

In the ordinary course of business, we are periodically a party to lawsuits. From time to time, oil and natural gas producers, including EXCO, have been named in various lawsuits alleging underpayment of royalties and the allocation of production costs in connection with oil and natural gas sold. We have reserved our estimated exposure and do not believe it was material to our current, or future, financial position or results of operations.

We believe that we have properly reflected any potential exposure in our financial position when determined to be both probable and estimable. See further discussion of the litigation related to the Participation Agreement as part of "Item 1A. Risk Factors", "Item 3. Legal Proceedings" and "Item 7. Management's Discussion and Analysis".

9. Employee benefit plans

We sponsor a 401(k) plan for our employees and matched 100% of employee contributions. Our matching contributions were \$5.2 million, \$7.1 million and \$8.8 million for the years ended December 31, 2015, 2014 and 2013, respectively. We suspended our employer matching program for 2016 in response to depressed oil and natural gas prices.

10. Earnings per share

The following table presents the basic and diluted earnings (loss) per share computations for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
(in thousands, except per share data)	**2015**	**2014**	**2013**
Basic net income (loss) per common share:			
Net income (loss)	$ (1,192,381)	$ 120,669	$ 22,204
Weighted average common shares outstanding	273,621	268,258	215,011
Net income (loss) per basic common share	$ (4.36)	$ 0.45	$ 0.10
Diluted net income (loss) per common share:			
Net income (loss)	$ (1,192,381)	$ 120,669	$ 22,204
Weighted average common shares outstanding	273,621	268,258	215,011
Dilutive effect of:			
Stock options	—	—	—
Restricted shares and restricted share units	—	118	420
Warrants	—	—	—
Subscription rights	—	—	15,481
Weighted average common shares and common share equivalents outstanding	273,621	268,376	230,912
Net income (loss) per diluted common share	$ (4.36)	$ 0.45	$ 0.10

The computation of diluted EPS excluded 39,544,192, 14,316,409 and 55,524,191 antidilutive common share equivalents for the years ended December 31, 2015, 2014 and 2013, respectively.

11. Equity-based compensation

Stock options and awards

Description of plan

Our 2005 Incentive Plan is a shareholder-approved plan authorizing the issuance of up to 45,500,000 restricted shares, restricted share units and stock options. As of December 31, 2015 and 2014, there were 17,773,172 and 19,763,916 shares, respectively, available for issuance under the 2005 Incentive Plan. Option grants count as one share against the total number of shares we have available for grant and restricted share grants count as 1.17 shares for awards granted before October 6, 2011, 2.1 shares for awards granted after October 6, 2011 and 1.74 shares for awards granted after June 11, 2013. The holders of restricted shares, excluding certain market-based restricted share awards discussed below, have voting rights, and upon vesting, the right to receive all accrued and unpaid dividends.

Stock options

Our outstanding stock option expiration dates range from 5 to 10 years following the date of grant and have a weighted average remaining life of 3.4 years. Pursuant to the 2005 Incentive Plan, 25% of the options vest immediately with an additional 25% to vest on each of the next three anniversaries of the date of the grant.

The following table summarizes stock option activity related to our employees under the 2005 Incentive Plan for the years ended December 31, 2015, 2014 and 2013:

	Stock Options	Weighted average exercise price per share	Weighted average remaining terms (in years)	Aggregate intrinsic value
Options outstanding at December 31, 2012	14,015,795	$ 13.20		
Granted	2,886,500	7.48		
Forfeitures	(4,969,877)	11.32		
Exercised	(220,675)	7.66		
Options outstanding at December 31, 2013	11,711,743	12.69		
Granted	141,525	5.24		
Forfeitures	(1,700,250)	12.71		
Exercised	(2,500)	5.22		
Options outstanding at December 31, 2014	10,150,518	12.58		
Granted	—	—		
Forfeitures	(4,538,858)	12.30		
Exercised	—	—		
Options outstanding at December 31, 2015	5,611,660	$ 12.81	3.4	$ —
Options exercisable at December 31, 2015	5,276,336	$ 13.18	3.2	$ —

The weighted average fair value of stock options on the date of the grant during the years ended December 31, 2014 and 2013 was $2.23 and $3.53, respectively. The total intrinsic value of stock options exercised for the years ended December 31, 2014 and 2013 was $0.0 million and $0.2 million, respectively.

The fair value of each option grant is estimated on the date of grant using the Black-Scholes option pricing model. The exercise price of the options is based on the fair market value of the common shares on the date of grant. No options were granted during 2015. The following assumptions were used for the options included in the table above, for the years ended December 31:

	2014	2013
Expected life	7.5 years	3.8 to 7.5 years
Risk-free rate of return	2.25 - 2.61 %	0.48 - 2.49 %
Volatility	59.46 - 59.61 %	49.47 - 59.86 %
Dividend yield	3.36 - 4.34 %	2.27 - 3.87 %

Expected life was determined based on EXCO's exercise history. Risk-free rate of return is a rate of a similar term U.S. Treasury zero coupon bond. Volatility was determined based on the weighted average of historical volatility of our common shares and the daily closing prices from comparable public companies. Dividend yield was determined based on EXCO's expected annual dividend and the market price of our common stock on the date of grant.

Service-based restricted share awards

Our service-based restricted share awards are valued at the closing price of our common shares on the date of grant and vest over a range of two to five years. A summary of our service-based restricted share activity for the years ended December 31, 2015, 2014 and 2013 are as follows:

	Shares	Weighted average grant date fair value per share
Non-vested shares outstanding at December 31, 2012	2,806,365	$ 10.16
Granted	556,700	7.15
Vested	(832,706)	10.47
Forfeited	(602,045)	9.84
Non-vested shares outstanding at December 31, 2013	1,928,314	$ 9.26
Granted	1,339,782	5.20
Vested	(1,109,866)	9.79
Forfeited	(280,301)	6.89
Non-vested shares outstanding at December 31, 2014	1,877,929	$ 6.40
Granted	4,414,470	1.05
Vested	(847,446)	6.80
Forfeited	(903,383)	3.17
Non-vested shares outstanding at December 31, 2015	4,541,570	$ 1.77

Market-based restricted share awards

On August 13, 2013, EXCO's officers were granted a market-based restricted share award with vesting dependent on the Company's common share price achieving certain price targets. There were 290,200 shares outstanding on December 31, 2015, including 145,100 shares that will be vested following any 30 consecutive trading days in which the company's common stock equals or exceeds $10.00 per share and 145,100 shares will be vested following any 30 consecutive trading days in which the Company's common shares equals or exceeds $15.00 per share ("Target Price Awards"). The shares expire on August 13, 2018 and are subject to vesting provisions depending on when the target price attainment date occurs. No such awards were granted in 2015 or 2014 and no awards have vested to date.

On July 1, 2014, EXCO's officers were granted restricted share units ("RSU") which have a vesting percentage between 0% and 200% depending on EXCO's total shareholder return in comparison to an identified peer group. These units will vest on the third anniversary of the date of grant, subject to the achievement of certain criteria. Total compensation expense will be recognized over the vesting period using the straight-line method. No such awards were granted in 2015.

The grant date fair values of our market-based restricted share awards and restricted share units were determined using a Monte Carlo model which uses company-specific inputs to generate different stock price paths.

A summary of our market-based restricted share activity for the years ended December 31, 2015 and 2014 is as follows:

	Target Price Awards		RSUs	
	Shares	Weighted average grant date fair value per share	Shares	Weighted average grant date fair value per share
Non-vested shares/units outstanding at December 31, 2014	401,400	$ 6.36	716,150	$ 7.33
Granted	—	—	—	—
Vested	—	—	—	—
Forfeited	(111,200)	6.36	(169,272)	7.33
Non-vested shares/units outstanding at December 31, 2015	290,200	$ 6.36	546,878	$ 7.33

Liability-classified awards

On July 1, 2015, EXCO's officers were granted 2,496,250 performance-based share units ("PSU") as a part of its equity compensation program. Each participant is eligible to vest in and receive a number of PSUs, ranging from 0% to 200% of the target number of PSUs granted, based on the attainment of total shareholder return goals on the period commencing on and including the date of grant and ending on the third anniversary of the grant date. Each PSU represents a non-equity unit with a conversion value equal to the fair market value of a share of EXCO's common stock. Under the terms of the agreements, the Company is required to convert vested PSUs into a cash payment in an aggregate amount equal to the number of vested PSUs multiplied by the fair market value of a share of common stock as of the vesting date, less applicable withholdings and deductions, as soon as administratively practicable following the determination that the vesting conditions have been achieved.

A summary of the PSUs for the years ended December 31, 2015 is as follows:

	Shares	Weighted average fair value per share
Non-vested units outstanding at December 31, 2014	—	$ —
Granted	2,496,250	1.45
Vested	—	—
Forfeited	(381,250)	1.25
Non-vested units outstanding at December 31, 2015	2,115,000	$ 2.39

The PSUs are considered liability-classified awards because of the cash-settlement feature. At December 31, 2015, we recorded a liability of $0.6 million related to the PSUs included in the Asset retirement obligations and other long-term liabilities line item on our Consolidated Balance Sheets. Compensation costs associated with the PSUs are re-measured each interim reporting period and an adjustment is recorded in General and administrative expenses line item in our Consolidated Statements of Operations.

The fair values of the PSUs were determined using a Monte Carlo model. The ranges for the assumptions used in the Monte Carlo model for the PSUs during 2015 are as follows:

Assumption	Range during 2015
Risk-free rate of return	0.85 - 1.18 %
Volatility	62.58 - 95.79 %
Dividend yield	0.00 - 0.00 %

Warrants

On September 8, 2015, EXCO issued warrants to ESAS in four tranches to purchase an aggregate of 80,000,000 common shares. The warrants were issued as an additional performance incentive under the services and investment agreement which is described in more detail in "Note. 13. Related party transactions". The table below lists the number of common shares issuable upon exercise of the warrants at each exercise price and the term of the warrants.

Tranche	Number of shares issuable	Exercise Price	Term
Tranche A	15,000,000	$2.75	April 30, 2019
Tranche B	20,000,000	$4.00	March 31, 2020
Tranche C	20,000,000	$7.00	March 31, 2021
Tranche D	25,000,000	$10.00	March 31, 2021

The warrants will vest on March 31, 2019 and their exercisability is subject to EXCO's common share price achieving certain performance hurdles as compared to the peer group. If EXCO's performance rank is in the bottom half of the peer group, then the warrants will be forfeited and void. The number of the exercisable shares under the warrants increases linearly from 32,000,000 to 80,000,000 as EXCO's performance rank increases from the 50th to 75th percentile, as compared to the peer group. If EXCO's performance rank is in the 75th percentile or above, then all 80,000,000 warrants will be exercisable. The performance measurement period began on March 31, 2015 and will end on March 31, 2019. As of December 31, 2015, EXCO's performance rank during the measurement period was above the 75th percentile of the peer group.

Prior to March 31, 2019, if EXCO terminates the agreement for any reason other than for cause (as defined in the agreement), or ESAS terminates the agreement for cause (as defined in the agreement), then all of the warrants will fully vest and become exercisable. Prior to March 31, 2019, if ESAS terminates the agreement for any reason other than for cause, or EXCO terminates the agreement for cause, then each of the warrants will be canceled and forfeited. On August 18, 2015, EXCO's shareholders approved, among other things, the increase to the authorized number of common shares available for issuance to 780,000,000 which ensures that an adequate number of common shares are available for issuance, including the shares to be reserved for issuance under the warrants issued to ESAS.

In accordance with FASB ASC Topic 718, *Compensation - Stock Compensation* ("ASC 718"), the grant date of the warrants was established upon approval of EXCO's shareholders and the closing of the services and investment agreement which occurred on September 8, 2015. The fair value of the warrants is dependent on factors such as our share price, historical volatility, risk-free rate and performance relative to our peer group and is determined using a Monte Carlo model. The table below shows the aggregate estimated fair value of the warrants as of December 31, 2015:

Tranche	Number of shares issuable	Estimated fair value per warrant	Estimated fair value (in millions)
Tranche A	15,000,000	$0.50	$7.5
Tranche B	20,000,000	$0.50	10.0
Tranche C	20,000,000	$0.48	9.6
Tranche D	25,000,000	$0.40	10.0
			$37.1

Compensation costs

All of our stock options, restricted shares and PSUs are accounted for in accordance with ASC 718 and are classified as equity except for the PSUs. As required by ASC 718, the granting of options and awards to our employees under the 2005 Incentive Plan are share-based payment transactions and are to be treated as compensation expense by us with a corresponding increase to additional paid-in capital.

Total share-based compensation to employees to be recognized on unvested options, restricted share awards and RSUs as of December 31, 2015 was $7.9 million and will be recognized over a weighted average period of 1.9 years.

The measurement of the warrants is accounted for in accordance with ASC Topic 505-50, *Equity-Based Payments to Non-Employees*, which requires the warrants to be re-measured each interim reporting period until the completion of the services under the agreement and an adjustment is recorded in the statement of operations within equity-based compensation expense. For the year ended December 31, 2015, we recognized equity-based compensation related to the warrants of $3.2 million.

The following is a reconciliation of our compensation expense for the years ended December 31, 2015, 2014 and 2013:

	Year Ended December 31,		
(in thousands)	2015	2014	2013
Equity-based compensation expense (1)	$ 7,198	$ 4,962	$ 10,748
Equity-based compensation capitalized	3,428	5,498	7,288
Total equity-based compensation	$ 10,626	$ 10,460	$ 18,036
Compensation expense on liability-classified awards (2)	$ 396	$ —	$ —

(1) Equity-based compensation expense includes share-based compensation to employees and equity-based compensation for warrants issued to ESAS in 2015.
(2) Compensation expense on liability-classified awards is net of compensation capitalized of $0.2 million.

We did not recognize a tax benefit attributable to our equity-based compensation for the years ended December 31, 2015, 2014 and 2013.

12. Income taxes

The income tax provision attributable to our income (loss) before income taxes for the years ended December 31, 2015, 2014 and 2013, consisted of the following:

(in thousands)	Year ended December 31, 2015	2014	2013
Current:			
Federal	$ —	$ —	$ —
State	—	—	—
Total current income tax (benefit)	$ —	$ —	$ —
Deferred:			
Federal	$ (414,834)	$ 45,797	$ 25,626
State	(45,009)	18,960	3,239
Valuation allowance	459,843	(64,757)	(28,865)
Total deferred income tax (benefit)	—	—	—
Total income tax (benefit)	$ —	$ —	$ —

We have net operating loss carryforwards ("NOLs") for United States income tax purposes that have been generated from our operations. Our NOLs are scheduled to expire if not utilized between 2028 and 2034. As a result of the repurchase of a portion of our senior unsecured notes during 2015, we had cancellation of debt income for tax purposes. We reduced our NOLs, including the entire tax net operating loss for year ended December 31, 2015, by the amount of cancellation of debt income of approximately $538.0 million.

NOLs and alternative minimum tax credits available for utilization as of December 31, 2015 were approximately $1.8 billion and $1.5 million, respectively. We generated a net capital loss of approximately $105.6 million during the year ended December 31, 2014 as a result of the sale of our interest in Compass.

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. We adopted ASU 2015-17 in the fourth quarter of 2015 and applied the guidance retrospectively which resulted in the reclassification of $35.9 million of net current deferred income tax liabilities to non-current as of December 31, 2014. See "Note 2. Summary of significant accounting policies" for description of ASU 2015-17. Significant components of our deferred tax liabilities and assets are as follows:

(in thousands)	December 31, 2015	December 31, 2014
Non-current deferred tax assets:		
Net operating loss and AMT credits carryforwards	$ 689,441	$ 781,899
Capital loss carryforwards	40,356	40,356
Equity-based compensation	17,372	14,856
Oil and natural gas properties, gathering assets, and equipment	356,471	—
Debt restructuring	122,900	—
Goodwill	1,308	5,419
Investment in partnerships	76,099	72,988
Other	3,387	2,668
Total non-current deferred tax assets	1,307,334	918,186
Valuation allowance	(1,286,695)	(826,852)
Total non-current deferred tax assets	20,639	91,334
Non-current deferred tax liabilities:		
Oil and natural gas properties, gathering assets, and equipment	$ —	$ (51,961)
Derivative financial instruments	(20,639)	(39,373)
Total non-current deferred tax liabilities	(20,639)	(91,334)
Net non-current deferred tax assets (liabilities)	$ —	$ —

A reconciliation of our income tax provision (benefit) computed by applying the statutory United States federal income tax rate to our income (loss) before income taxes for the years ended December 31, 2015, 2014 and 2013 is presented in the following table:

(in thousands)	Year Ended December 31, 2015	2014	2013
Federal income taxes (benefit) provision at statutory rate of 35%	$ (417,333)	$ 42,234	$ 7,772
Increases (reductions) resulting from:			
Goodwill	—	—	16,382
Adjustments to the valuation allowance	459,843	(64,757)	(28,865)
Non-deductible compensation	2,399	3,409	1,328
State taxes net of federal benefit	(45,009)	3,464	3,239
State tax rate change	—	15,496	—
Other	100	154	144
Total income tax provision	$ —	$ —	$ —

During years ended 2015, 2014 and 2013, both federal and state income tax expense or tax benefit were reduced to zero by a corresponding increase or decrease to the valuation allowance previously recognized against net deferred tax assets. The net result was no income tax provision for years ended December 31, 2015, 2014 and 2013.

We adopted the provisions of ASC 740-10 on January 1, 2007. As a result of the implementation of ASC 740-10, the Company did not recognize any liabilities for unrecognized tax benefits. As of December 31, 2015, 2014 and 2013, the Company's policy is to recognize interest related to unrecognized tax benefits of interest expense and penalties in operating expenses. The Company has not accrued any interest or penalties relating to unrecognized tax benefits in the consolidated financial statements.

We file a corporate consolidated income tax return for U.S. federal income tax purposes and file income tax return in various states. With few exceptions, we are no longer subject to U.S. federal and state and local examinations by tax authorities for years before 2006. The Company was notified during the year ended December 31, 2013 that the corporate tax return for the year ended December 31, 2011 would be examined by the Internal Revenue Service. In addition, two pass-through entities in which the Company owns an interest will also be examined for the year ended December 31, 2010. During 2014, the Internal Revenue Service completed the exam on the corporate return and on one of the two pass-through entities. No changes were made to either the corporate or partnership return as originally filed as a result of the exams. The Company was notified during 2015 that the Internal Revenue Service has completed its examination of the remaining partnership return and no changes were made to the return as originally filed.

13. Related party transactions

OPCO

OPCO serves as the operator of our wells in the Appalachia JV and we advance funds to OPCO on an as needed basis. We did not advance any funds to OPCO during the years ended December 31, 2015 or 2014. OPCO may distribute any excess cash equally between us and BG Group when its operating cash flows are sufficient to meet its capital requirements. There are service agreements between us and OPCO whereby we provide administrative and technical services for which we are reimbursed. For the years ended December 31, 2015, 2014 and 2013 these transactions included the following:

(in thousands)	Year Ended December 31, 2015	2014	2013
Advances to OPCO	$ —	$ —	$ 28,378
Amounts received from OPCO	30,577	53,002	43,632

As of December 31, 2015 and 2014, the amounts owed under the service agreements were as follows:

(in thousands)	December 31, 2015	December 31, 2014
Amounts due to EXCO (1)	$ 1,733	$ 2,799
Amounts due from EXCO (1)	10,410	—

(1) Advances to OPCO are recorded in "Inventory and other" on our Condensed Consolidated Balance Sheets. Any amounts we owe to OPCO are netted against the advance until the advances are utilized. If the advances are fully utilized, we record amounts owed in "Accounts payable and accrued liabilities" on our Condensed Consolidated Balance Sheets.

Services and investment agreement

On March 31, 2015, we entered into a four year services and investment agreement with ESAS, a wholly-owned subsidiary of Bluescape Resources Company LLC ("Bluescape"). As part of this agreement, ESAS provides us with certain strategic advisory services, including the development and execution of a strategic improvement plan. On September 8, 2015 we closed the services and investment agreement with ESAS and C. John Wilder, Executive Chairman of Bluescape, was appointed as a member of our Board of Directors and as Executive Chairman of the Board of Directors.

On September 8, 2015, ESAS completed the purchase of 5,882,353 common shares from EXCO, par value $0.001 per share, at a price per share of $1.70, pursuant to the agreement. In addition, the services and investment agreement was amended to reduce the additional amount of common shares to at least $13.5 million that ESAS is obligated to purchase through open market purchases. ESAS completed the required investment on December 31, 2015 by purchasing a total 12,464,130 common shares during the fourth quarter of 2015. As of December 31, 2015, ESAS owned common shares of EXCO with an aggregate cost basis of $23.5 million and is the beneficial owner of approximately 6.5% of our outstanding common shares.

As consideration for the services to be provided under the agreement, EXCO will pay ESAS a monthly fee of $300,000 and an annual incentive payment of up to $2.4 million per year that will be based on EXCO's common share price achieving certain performance hurdles as compared to a peer group, provided that payment for the services will be held in escrow and contingent upon completion of the entire first year of services and required investment in EXCO. If EXCO's performance rank is below the 50th percentile of the peer group, then the incentive payment will be zero. The incentive payment increases linearly from $1.0 million to $2.4 million as EXCO's performance rank increases from the 50th to 75th percentile, as compared to the peer group. If EXCO's performance rank is in the 75th percentile or above, then the incentive payment will be $2.4 million. For the year ended December 31, 2015, we recognized $1.8 million expense for the annual incentive payment as a result of EXCO's performance rank above the 75th percentile of the peer group.

As an additional performance incentive under the services and investment agreement, EXCO issued warrants to ESAS in four tranches to purchase an aggregate of 80,000,000 common shares. See "Note 11. Equity-based compensation" for further discussion of the warrants.

Fairfax Term Loan

Hamblin Watsa Investment Counsel Ltd. ("Hamblin Watsa"), a wholly owned subsidiary of Fairfax, is the administrative agent of the Fairfax Term Loan and certain affiliates of Fairfax are lenders under the Fairfax Term Loan. Samuel A. Mitchell, a member of our Board of Directors, is a Managing Director of Hamblin Watsa and a member of Hamblin Watsa's investment committee, which consists of seven members that manage the investment portfolio of Fairfax. As an administrative agent of the Fairfax Term Loan, Fairfax received a one-time fee of $6.0 million from EXCO upon closing and received $6.9 million of interest payments as of December 31, 2015. At December 31, 2015, Fairfax was the beneficial owner of approximately 9.0% of our outstanding common shares. See "Note 5. Debt" for additional information.

Rights offering

As discussed in "Note 14. Rights offering and other equity transactions", we entered into investment agreements and closed a related private placement of our common shares with certain affiliates of WL Ross & Co. LLC ("WL Ross") and Hamblin Watsa. Wilbur L. Ross, Jr., the Chairman and Chief Executive Officer of WL Ross, and Samuel A. Mitchell, Managing Director of Hamblin Watsa, both of whom serve on EXCO's Board of Directors.

14. Rights Offering and other equity transactions

On December 19, 2013, the Company granted subscription rights to holders of common shares which entitled the holder to purchase 0.25 of a share of our common stock for each share of common stock owned by such holders. Each subscription right entitled the holder to a basic subscription right and an over-subscription privilege. The basic subscription right entitled the holder to purchase 0.25 of a share of the Company's common shares at a subscription price equal to $5.00 per share of common stock. The over-subscription privilege entitled the holders who exercised their basic subscription rights in full (including in respect of subscription rights purchased from others) to purchase any or all shares of our common shares that other rights holders did not purchase through the purchase of their basic subscription rights at a subscription price equal to $5.00 per share of our common shares. The subscription rights expired if they were not exercised by January 9, 2014.

The Company entered into two investment agreements ("Investment Agreements") in connection with the rights offering, each dated as of December 17, 2013, one with certain affiliates of WL Ross and one with Hamblin Watsa pursuant to which, subject to the terms and conditions thereof, each of them has severally agreed to subscribe for and purchase, in a private placement, its respective pro rata portion of shares under the basic subscription right and all unsubscribed shares under the over-subscription privilege subject to pro rata allocation among the subscription rights holders who have elected to exercise their over-subscription privilege.

The rights offering and related transactions under the Investment Agreements closed on January 17, 2014 ("Rights Offering") which resulted in the issuance of 54,574,734 shares for proceeds of $272.9 million. We used the proceeds to pay indebtedness under the EXCO Resources Credit Agreement. WL Ross and Hamblin Watsa purchased 19,599,973 and 6,726,712 shares, respectively, pursuant to their basic subscription rights and the over-subscription privilege.

Preferred Shares

We canceled all classes of our preferred shares in 2014. We have 10,000,000 preferred shares authorized with no preferred shares issued and outstanding. Our issued and outstanding shares of capital stock consist solely of common shares.

15. Condensed consolidating financial statements

As of December 31, 2015, the majority of EXCO's subsidiaries were guarantors under the EXCO Resources Credit Agreement, the indentures governing the 2018 Notes and 2022 Notes and the agreements governing the Second Lien Term Loans. All of our non-guarantor subsidiaries were considered unrestricted subsidiaries under the Second Lien Term Loans and the indentures governing the 2018 Notes and 2022 Notes, with the exception of our equity investment in OPCO.

Set forth below are condensed consolidating financial statements of EXCO, the guarantor subsidiaries and the non-guarantor subsidiaries. The 2018 Notes, 2022 Notes and the Second Lien Term Loans, which were issued by EXCO Resources, Inc., are jointly and severally guaranteed by substantially all of our subsidiaries (referred to as Guarantor Subsidiaries). For purposes of this footnote, EXCO Resources, Inc. is referred to as Resources to distinguish it from the Guarantor Subsidiaries. Each of the Guarantor Subsidiaries is a 100% owned subsidiary of Resources and the guarantees are unconditional as they relate to the assets of the Guarantor Subsidiaries.

The following financial information presents consolidating financial statements, which include:

- Resources;
- the Guarantor Subsidiaries;
- the Non-Guarantor Subsidiaries;
- elimination entries necessary to consolidate Resources, the Guarantor Subsidiaries and the Non-Guarantor Subsidiaries; and
- EXCO on a consolidated basis.

Investments in subsidiaries are accounted for using the equity method of accounting for the disclosures within this footnote. The financial information for the Guarantor Subsidiaries and the Non-Guarantor Subsidiaries is presented on a combined basis. The elimination entries primarily eliminate investments in subsidiaries and intercompany balances and transactions.

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2015

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 34,296	$ (22,049)	$ —	$ —	$ 12,247
Restricted cash	2,100	19,120	—	—	21,220
Other current assets	51,133	65,201	—	—	116,334
Total current assets	87,529	62,272	—	—	149,801
Equity investments	—	—	40,797	—	40,797
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties and development costs not being amortized	—	115,377	—	—	115,377
Proved developed and undeveloped oil and natural gas properties	330,775	2,739,655	—	—	3,070,430
Accumulated depletion	(330,775)	(2,296,988)	—	—	(2,627,763)
Oil and natural gas properties, net	—	558,044	—	—	558,044
Other property and equipment, net	749	27,063	—	—	27,812
Investments in and advances to affiliates, net	616,940	—	—	(616,940)	—
Deferred financing costs, net	8,408	—	—	—	8,408
Derivative financial instruments	6,109	—	—	—	6,109
Goodwill	13,293	149,862	—	—	163,155
Total assets	$ 733,028	$ 797,241	$ 40,797	$ (616,940)	$ 954,126
Liabilities and shareholders' equity					
Current liabilities	$ 74,472	$ 178,447	$ —	$ —	$ 252,919
Long-term debt	1,320,279	—	—	—	1,320,279
Other long-term liabilities	600	42,651	—	—	43,251
Payable to parent	—	2,276,594	—	(2,276,594)	—
Total shareholders' equity	(662,323)	(1,700,451)	40,797	1,659,654	(662,323)
Total liabilities and shareholders' equity	$ 733,028	$ 797,241	$ 40,797	$ (616,940)	$ 954,126

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING BALANCE SHEET

December 31, 2014

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Assets					
Current assets:					
Cash and cash equivalents	$ 86,837	$ (40,532)	$ —	$ —	$ 46,305
Restricted cash	—	23,970	—	—	23,970
Other current assets	110,145	150,346	—	—	260,491
Total current assets	196,982	133,784	—	—	330,766
Equity investments	—	—	55,985	—	55,985
Oil and natural gas properties (full cost accounting method):					
Unproved oil and natural gas properties and development costs not being amortized	—	276,025	—	—	276,025
Proved developed and undeveloped oil and natural gas properties	335,838	3,516,235	—	—	3,852,073
Accumulated depletion	(330,771)	(2,083,690)	—	—	(2,414,461)
Oil and natural gas properties, net	5,067	1,708,570	—	—	1,713,637
Other property and equipment, net	1,269	23,375	—	—	24,644
Investments in and advances to affiliates, net	1,746,931	—	—	(1,746,931)	—
Deferred financing costs, net	14,617	—	—	—	14,617
Derivative financial instruments	2,138	—	—	—	2,138
Goodwill	13,293	149,862	—	—	163,155
Total assets	$ 1,980,297	$ 2,015,591	$ 55,985	$ (1,746,931)	$ 2,304,942
Liabilities and shareholders' equity					
Current liabilities	$ 39,506	$ 289,930	$ —	$ —	$ 329,436
Long-term debt	1,430,516	—	—	—	1,430,516
Other long-term liabilities	271	34,715	—	—	34,986
Payable to parent	—	2,058,683	—	(2,058,683)	—
Total shareholders' equity	510,004	(367,737)	55,985	311,752	510,004
Total liabilities and shareholders' equity	$ 1,980,297	$ 2,015,591	$ 55,985	$ (1,746,931)	$ 2,304,942

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended December 31, 2015

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 4	$ 328,327	$ —	$ —	$ 328,331
Costs and expenses:					
Oil and natural gas production	37	76,496	—	—	76,533
Gathering and transportation	—	99,321	—	—	99,321
Depletion, depreciation and amortization	943	214,483	—	—	215,426
Impairment of oil and natural gas properties	9,316	1,206,054	—	—	1,215,370
Accretion of discount on asset retirement obligations	4	2,273	—	—	2,277
General and administrative	(4,313)	63,131	—	—	58,818
Other operating items	1,646	(1,185)	—	—	461
Total costs and expenses	7,633	1,660,573	—	—	1,668,206
Operating loss	(7,629)	(1,332,246)	—	—	(1,339,875)
Other income (expense):					
Interest expense, net	(106,082)	—	—	—	(106,082)
Gain on derivative financial instruments	75,869	—	—	—	75,869
Gain on restructuring and extinguishment of debt	193,276	—	—	—	193,276
Other income	87	35	—	—	122
Equity loss	—	—	(15,691)	—	(15,691)
Net loss from consolidated subsidiaries	(1,347,902)	—	—	1,347,902	—
Total other income (expense)	(1,184,752)	35	(15,691)	1,347,902	147,494
Loss before income taxes	(1,192,381)	(1,332,211)	(15,691)	1,347,902	(1,192,381)
Income tax expense	—	—	—	—	—
Net loss	$ (1,192,381)	$ (1,332,211)	$ (15,691)	$ 1,347,902	$ (1,192,381)

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended December 31, 2014

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 3,649	$ 614,889	$ 41,731	$ —	$ 660,269
Costs and expenses:					
Oil and natural gas production	394	77,334	16,598	—	94,326
Gathering and transportation	—	97,784	3,790	—	101,574
Depletion, depreciation and amortization	3,174	244,761	15,634	—	263,569
Impairment of oil and natural gas properties	—	—	—	—	—
Accretion of discount on asset retirement obligations	16	2,107	567	—	2,690
General and administrative	(3,342)	66,686	2,576	—	65,920
Other operating items	(134)	5,459	(10)	—	5,315
Total costs and expenses	108	494,131	39,155	—	533,394
Operating income	3,541	120,758	2,576	—	126,875
Other income (expense):					
Interest expense, net	(92,049)	—	(2,235)	—	(94,284)
Gain on derivative financial instruments	87,565	—	100	—	87,665
Other income	226	—	15	—	241
Equity income	—	—	172	—	172
Net earnings from consolidated subsidiaries	121,386	—	—	(121,386)	—
Total other income (expense)	117,128	—	(1,948)	(121,386)	(6,206)
Income before income taxes	120,669	120,758	628	(121,386)	120,669
Income tax expense	—	—	—	—	—
Net income	$ 120,669	$ 120,758	$ 628	$ (121,386)	$ 120,669

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF OPERATIONS

For the year ended December 31, 2013

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Revenues:					
Oil and natural gas	$ 9,136	$ 582,158	$ 43,015	$ —	$ 634,309
Costs and expenses:					
Oil and natural gas production	2,440	63,716	17,092	—	83,248
Gathering and transportation	—	97,166	3,479	—	100,645
Depletion, depreciation and amortization	5,917	225,499	14,359	—	245,775
Impairment of oil and natural gas properties	—	108,546	—	—	108,546
Accretion of discount on asset retirement obligations	63	1,881	570	—	2,514
General and administrative	23,125	66,558	2,195	—	91,878
Gain on divestitures and other operating items	(25,950)	(151,549)	(19)	—	(177,518)
Total costs and expenses	5,595	411,817	37,676	—	455,088
Operating income (loss)	3,541	170,341	5,339	—	179,221
Other income (expense):					
Interest expense, net	(99,815)	—	(2,774)	—	(102,589)
Gain (loss) on derivative financial instruments	1,439	(177)	(1,582)	—	(320)
Other income (loss)	(1,068)	229	11	—	(828)
Equity loss	—	—	(53,280)	—	(53,280)
Net earnings from consolidated subsidiaries	118,107	—	—	(118,107)	—
Total other income (expense)	18,663	52	(57,625)	(118,107)	(157,017)
Income (loss) before income taxes	22,204	170,393	(52,286)	(118,107)	22,204
Income tax expense	—	—	—	—	—
Net income (loss)	$ 22,204	$ 170,393	$ (52,286)	$ (118,107)	$ 22,204

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the year ended December 31, 2015

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by operating activities	$ 34,532	$ 99,495	$ —	$ —	$ 134,027
Investing Activities:					
Additions to oil and natural gas properties, gathering assets and equipment and property acquisitions	(2,601)	(322,597)	—	—	(325,198)
Proceeds from disposition of property and equipment	686	6,711	—	—	7,397
Restricted cash	—	4,850	—	—	4,850
Net changes in advances to joint ventures	—	10,663	—	—	10,663
Equity investments and other	—	1,455	—	—	1,455
Advances/investments with affiliates	(217,906)	217,906	—	—	—
Net cash used in investing activities	(219,821)	(81,012)	—	—	(300,833)
Financing Activities:					
Borrowings under credit agreements	165,000	—	—	—	165,000
Repayments under credit agreements	(300,000)	—	—	—	(300,000)
Proceeds received from issuance of Fairfax Term Loan	300,000	—	—	—	300,000
Repurchases of 2018 Notes	(12,008)	—	—	—	(12,008)
Payment on Exchange Term Loan	(8,827)	—	—	—	(8,827)
Proceeds from issuance of common shares, net	9,693	—	—	—	9,693
Payment of common share dividends	(164)	—	—	—	(164)
Deferred financing costs and other	(20,946)	—	—	—	(20,946)
Net cash provided by financing activities	132,748	—	—	—	132,748
Net increase (decrease) in cash	(52,541)	18,483	—	—	(34,058)
Cash at beginning of period	86,837	(40,532)	—	—	46,305
Cash at end of period	$ 34,296	$ (22,049)	$ —	$ —	$ 12,247

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the year ended December 31, 2014

(in thousands)	Resources	Guarantor Subsidiaries	Non-Guarantor Subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by (used in) operating activities	$ (84,067)	$ 428,029	$ 18,131	$ —	$ 362,093
Investing Activities:					
Additions to oil and natural gas properties, gathering assets and equipment and property acquisitions	(2,531)	(395,974)	(4,061)	—	(402,566)
Proceeds from disposition of property and equipment	99,612	95,594	(7,551)	—	187,655
Restricted cash	—	(3,400)	—	—	(3,400)
Net changes in advances to joint ventures	—	(5,026)	—	—	(5,026)
Distributions from Compass	5,856	—	—	(5,856)	—
Equity investments and other	—	1,749	—	—	1,749
Advances/investments with affiliates	125,612	(125,612)	—	—	—
Net cash provided by (used in) investing activities	228,549	(432,669)	(11,612)	(5,856)	(221,588)
Financing Activities:					
Borrowings under credit agreements	100,000	—	—	—	100,000
Repayments under credit agreements	(959,874)	—	(5,096)	—	(964,970)
Proceeds received from issuance of 2022 Notes	500,000	—	—	—	500,000
Proceeds from issuance of common shares, net	271,773	—	—	—	271,773
Payment of common share dividends	(41,060)	—	—	—	(41,060)
Compass cash distribution	—	—	(5,856)	5,856	—
Deferred financing costs and other	(10,324)	—	(102)	—	(10,426)
Net cash used in financing activities	(139,485)	—	(11,054)	5,856	(144,683)
Net increase (decrease) in cash	4,997	(4,640)	(4,535)	—	(4,178)
Cash at beginning of period	81,840	(35,892)	4,535	—	50,483
Cash at end of period	$ 86,837	$ (40,532)	$ —	$ —	$ 46,305

EXCO RESOURCES, INC.

CONDENSED CONSOLIDATING STATEMENT OF CASH FLOWS

For the year ended December 31, 2013

(in thousands)	Resources	Guarantor Subsidiaries	Non-guarantor subsidiaries	Eliminations	Consolidated
Operating Activities:					
Net cash provided by (used in) operating activities	$ (32,678)	$ 365,770	$ 17,542	$ —	$ 350,634
Investing Activities:					
Additions to oil and natural gas properties, gathering assets and equipment	(15,767)	(1,242,667)	(38,818)	—	(1,297,252)
Proceeds from disposition of property and equipment	244,500	505,128	—	—	749,628
Restricted cash	—	49,515	—	—	49,515
Net changes in advances to joint ventures	—	10,645	—	—	10,645
Distributions from Compass	3,825	—	—	(3,825)	—
Equity investments and other	(1,303)	236,289	—	—	234,986
Advances/investments with affiliates	(59,575)	59,575	—	—	—
Net cash provided by (used in) investing activities	171,680	(381,515)	(38,818)	(3,825)	(252,478)
Financing Activities:					
Borrowings under the credit agreements	967,766	—	36,757	—	1,004,523
Repayments under the credit agreements	(1,015,900)	—	(6,885)	—	(1,022,785)
Proceeds from issuance of common shares, net	1,712	—	—	—	1,712
Payment of common share dividends	(43,214)	—	—	—	(43,214)
Compass cash distribution	—	—	(3,825)	3,825	—
Deferred financing costs and other	(33,317)	—	(236)	—	(33,553)
Net cash provided by (used in) financing activities	(122,953)	—	25,811	3,825	(93,317)
Net increase (decrease) in cash	16,049	(15,745)	4,535	—	4,839
Cash at beginning of period	65,791	(20,147)	—	—	45,644
Cash at end of period	$ 81,840	$ (35,892)	$ 4,535	$ —	$ 50,483

16. Quarterly financial data (unaudited)

The following are summarized quarterly financial data for the years ended December 31, 2015 and 2014:

	Quarter			
(in thousands, except per share amounts)	**1st**	**2nd**	**3rd**	**4th**
2015				
Oil and natural gas revenues	$ 86,320	$ 93,742	$ 83,526	$ 64,743
Operating loss (1)	(313,618)	(421,465)	(363,975)	(240,817)
Net loss (2)	$ (318,112)	$ (454,155)	$ (354,519)	$ (65,595)
Basic loss per share:				
Net loss	$ (1.17)	$ (1.67)	$ (1.30)	$ (0.24)
Weighted average shares	271,522	271,549	273,348	277,995
Diluted loss per share:				
Net loss	$ (1.17)	$ (1.67)	$ (1.30)	$ (0.24)
Weighted average shares	271,522	271,549	273,348	277,995
2014				
Oil and natural gas revenues	$ 198,472	$ 182,966	$ 151,042	$ 127,789
Operating income	57,423	43,312	22,799	3,341
Net income (loss)	$ (4,606)	$ 2,293	$ 41,569	$ 81,413
Basic earnings (loss) per share:				
Net income (loss)	$ (0.02)	$ 0.01	$ 0.15	$ 0.30
Weighted average shares	260,716	270,492	270,631	271,053
Diluted earnings (loss) per share:				
Net income (loss)	$ (0.02)	$ 0.01	$ 0.15	$ 0.30
Weighted average shares	260,716	271,226	272,066	271,053

(1) Operating loss for the first, second, third and fourth quarter of 2015 includes $276.3 million, $394.3 million, $339.4 million and $205.3 million, respectively, of impairments of oil and natural gas properties. See "Note 2. Summary of significant accounting policies" for further discussion.

(2) Net loss for the fourth quarter of 2015 includes a $193.3 million net gain on restructuring and extinguishment of debt. See "Note 5. Debt" for further discussion.

17. Supplemental information relating to oil and natural gas producing activities (unaudited)

The following supplemental information relating to our oil and natural gas producing activities for the years ended December 31, 2015, 2014 and 2013 is presented in accordance with ASC 932, *Extractive Activities, Oil and Gas.*

Presented below are costs incurred in oil and natural gas property acquisition, exploration and development activities:

(in thousands, except per unit amounts)		Amount
2015:		
Proved property acquisition costs	$	7,608
Unproved property acquisition costs		—
Total property acquisition costs		7,608
Development		215,239
Exploration costs (1)		13,306
Lease acquisitions and other		13,017
Capitalized asset retirement costs		881
Depletion per Boe	$	10.32
Depletion per Mcfe	$	1.72
2014:		
Proved property acquisition costs	$	10,562
Unproved property acquisition costs		—
Total property acquisition costs		10,562
Development		354,199
Exploration costs (2)		5,906
Lease acquisitions and other		9,681
Capitalized asset retirement costs		576
Depletion per Boe	$	11.42
Depletion per Mcfe	$	1.90
2013:		
Proved property acquisition costs	$	754,370
Unproved property acquisition costs		232,020
Total property acquisition costs (3)		986,390
Development		231,447
Exploration costs (4)		38,579
Lease acquisitions and other		14,835
Capitalized asset retirement costs		514
Depletion per Boe	$	8.82
Depletion per Mcfe	$	1.47

(1) Exploration costs in 2015 primarily relate to the wells drilled in the Buda formation in South Texas.

(2) Exploration costs in 2014 include $5.9 million in the Bossier shale in North Louisiana.

(3) Acquisition costs in 2013 include the acquisition of properties in the Haynesville and Eagle Ford shales and our proportionate share of Compass's acquisition of shallow Cotton Valley assets.

(4) Exploration costs in 2013 include $29.2 million in the Eagle Ford shale and $9.4 million in the Marcellus shale.

We retain independent engineering firms to prepare or audit annual year-end estimates of our future net recoverable oil and natural gas reserves. The estimated proved net recoverable reserves we show below include only those quantities that we expect to be commercially recoverable at prices and costs in effect at the balance sheet dates under existing regulatory practices and with conventional equipment and operating methods. Proved Developed Reserves represent only those reserves that we may recover through existing wells. Proved Undeveloped Reserves include those reserves that we may recover from new wells on undrilled acreage or from existing wells on which we must make a relatively major expenditure for recompletion or secondary recovery operations. All of our reserves are located onshore in the continental United States of America.

Discounted future cash flow estimates like those shown below are not intended to represent estimates of the fair value of our oil and natural gas properties. Estimates of fair value should also consider unproved 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 subjective and imprecise.

	Oil (Mbbls)	Natural Gas (Mmcf) (12)	Mmcfe (13)
December 31, 2012	5,570	975,966	1,009,386
Purchase of reserves in place (1)	16,022	304,139	400,271
Discoveries and extensions (2)	5,960	49,912	85,672
Revisions of previous estimates:			
Changes in price	457	276,730	279,472
Other factors (3)	(3,219)	(111,141)	(130,455)
Sales of reserves in place (4)	(8,224)	(308,850)	(358,194)
Production	(1,188)	(154,779)	(161,907)
December 31, 2013	15,378	1,031,977	1,124,245
Purchase of reserves in place (5)	—	7,316	7,316
Discoveries and extensions (6)	4,164	70,544	95,528
Revisions of previous estimates:			
Changes in price	45	168,064	168,334
Other factors (7)	1,737	120,802	131,224
Sales of reserves in place (8)	(1,401)	(118,705)	(127,111)
Production	(2,236)	(122,324)	(135,740)
December 31, 2014	17,687	1,157,674	1,263,796
Purchase of reserves in place (9)	459	122	2,876
Discoveries and extensions (10)	7,602	152,473	198,085
Revisions of previous estimates:			
Changes in price	(2,821)	(598,865)	(615,791)
Other factors (11)	(145)	184,641	183,771
Sales of reserves in place	(1)	(1,445)	(1,451)
Production	(2,342)	(109,926)	(123,978)
December 31, 2015	20,439	784,674	907,308

Estimated Quantities of Proved Developed and Proved Undeveloped Reserves

	Oil (Mbbls)	Natural Gas (Mmcf)	Mmcfe
Proved developed:			
December 31, 2015	12,056	364,932	437,268
December 31, 2014	14,429	504,636	591,210
December 31, 2013	11,274	669,644	737,291
Proved undeveloped:			
December 31, 2015	8,383	419,742	470,040
December 31, 2014	3,258	653,038	672,586
December 31, 2013	4,104	362,333	386,954

(1) Purchases of reserves in place include 115.7 Bcfe in the Eagle Ford shale, 260.0 Bcfe in the Haynesville shale, and 24.6 Bcfe for our proportionate share of Compass's acquisition of shallow Cotton Valley assets in East Texas/North Louisiana.

(2) New discoveries and extensions in 2013 include 36.5 Bcfe in the Eagle Ford shale, 33.6 Bcfe in the Marcellus shale, 10.2 Bcfe in the Haynesville shale, 3.9 Bcfe for conventional properties held by Compass in the Permian Basin, and 1.5 Bcfe for shale properties in the Permian Basin.

(3) Total revisions due to Other factors were downward revisions primarily in the Haynesville shale as a result of operational matters including scaling, liquid loading due to high-line pressure and the impact of drainage on new wells drilled directly offset to the unit wells.

(4) Sales of reserves in place in 2013 include 327.6 Bcfe as a result of our contribution of properties to Compass and 30.6 Bcfe from the sale of undeveloped properties in the Eagle Ford in connection with the Participation Agreement.

(5) Purchases of reserves in place in 2014 consist primarily of our acquisition of certain proved developed producing properties in the Shelby area of East Texas.

(6) New discoveries and extensions in 2014 included 48.7 Bcfe in the Haynesville shale, 26.1 Bcfe in the Eagle Ford Shale and 19.7 Bcfe in the Bossier shale. The discoveries and extensions within the Haynesville and Bossier shales primarily related to our development of properties within the Shelby area of East Texas.

(7) Total revisions due to Other factors include upward revisions of approximately 67.1 Bcfe in the Shelby area, approximately 45.9 Bcfe in the Appalachia region, and approximately 5.8 Bcfe in the Holly area. The upward revisions were primarily due to improved well performance resulting from enhanced well designs and completion techniques.

(8) Sales of reserves in place in 2014 consist primarily of the sale of our entire interest in Compass.

(9) Purchases of reserves in place include the acquisition of certain proved developed producing properties in the Eagle Ford shale in connection with the Participation Agreement.

(10) New discoveries and extensions in 2015 include 84.9 Bcfe and 41.0 Bcfe in the Haynesville shale and Bossier shale, respectively, related to our development of properties within the Shelby area of East Texas. Additionally, extensions and discoveries in 2015 included 24.7 Bcfe in the in the Haynesville shale related to the development of the Holly area in North Louisiana and 47.5 Bcfe in the Eagle Ford shale.

(11) Total revisions due to Other factors include upward revisions of approximately 152.2 Bcfe in the North Louisiana Holly area and are primarily due to modifications in the well design to incorporate more proppant and longer laterals. The upward revisions also included 36.7 Bcfe from our East Texas region primarily due to strong results in both the Haynesville and Bossier shales based on our enhanced completion methods. The upward revisions also reflect a reduction in capital costs and operating expenses.

(12) Beginning in 2015, we began reporting our NGLs as a component of natural gas as NGLs are not considered to be significant. Primarily all of our prior period NGLs were associated with properties owned by Compass, which EXCO divested in 2014. Prior period information has been conformed to be consistent with current period information.

(13) The above reserves do not include our equity interest in OPCO, which was not significant in any period presented.

Standardized measure of discounted future net cash flows

We have summarized the Standardized Measure related to our proved oil and natural gas reserves. We have based the following summary on a valuation of Proved Reserves using discounted cash flows based on prices as prescribed by the SEC, costs and economic conditions and a 10% discount rate. The additions to Proved Reserves from the purchase of reserves in place, and new discoveries and extensions could vary significantly from year to year; additionally, the impact of changes to reflect current prices and costs of reserves proved in prior years could also be significant. Accordingly, the information presented below should not be viewed as an estimate of the fair value of our oil and natural gas properties, nor should it be indicative of any trends.

(in thousands)	Amount
Year ended December 31, 2015:	
Future cash inflows	$ 2,684,362
Future production costs	1,280,795
Future development costs	641,768
Future income taxes	—
Future net cash flows	761,799
Discount of future net cash flows at 10% per annum	359,666
Standardized measure of discounted future net cash flows	$ 402,133
Year ended December 31, 2014:	
Future cash inflows	$ 6,097,207
Future production costs	2,094,796
Future development costs	1,124,873
Future income taxes	—
Future net cash flows	2,877,538
Discount of future net cash flows at 10% per annum	1,334,951
Standardized measure of discounted future net cash flows	$ 1,542,587
Year ended December 31, 2013:	
Future cash inflows	$ 5,176,030
Future production costs	2,207,230
Future development costs	904,116
Future income taxes	—
Future net cash flows	2,064,684
Discount of future net cash flows at 10% per annum	812,411
Standardized measure of discounted future net cash flows	$ 1,252,273

During recent years, prices paid for oil and natural gas have fluctuated significantly. The reference prices at December 31, 2015, 2014 and 2013 used in the above table, were $50.28, $94.99 and $96.78 per Bbl of oil, respectively, and $2.59, $4.35 and $3.67 per Mmbtu of natural gas, respectively. Each of the reference prices for oil and natural gas were adjusted for quality factors and regional differentials. These prices reflect the SEC rules requiring the use of simple average of the first day of the month price for the previous 12 month period for natural gas at Henry Hub and West Texas Intermediate crude oil at Cushing, Oklahoma.

The following are the principal sources of change in the Standardized Measure:

(in thousands)	Amount
Year ended December 31, 2015:	
Sales and transfers of oil and natural gas produced	$ (152,937)
Net changes in prices and production costs	(1,438,490)
Extensions and discoveries, net of future development and production costs	99,818
Development costs during the period	109,895
Changes in estimated future development costs	407,780
Revisions of previous quantity estimates	(232,325)
Sales of reserves in place	(1,632)
Purchase of reserves in place	6,892
Accretion of discount before income taxes	126,533
Changes in timing and other	(65,988)
Net change in income taxes	—
Net change	$ (1,140,454)
Year ended December 31, 2014:	
Sales and transfers of oil and natural gas produced	$ (464,369)
Net changes in prices and production costs	279,944
Extensions and discoveries, net of future development and production costs	196,796
Development costs during the period	189,155
Changes in estimated future development costs	(254,737)
Revisions of previous quantity estimates	412,296
Sales of reserves in place	(148,226)
Purchase of reserves in place	13,507
Accretion of discount before income taxes	125,227
Changes in timing and other	(59,279)
Net change in income taxes	—
Net change	$ 290,314
Year ended December 31, 2013:	
Sales and transfers of oil and natural gas produced	$ (450,415)
Net changes in prices and production costs	582,725
Extensions and discoveries, net of future development and production costs	197,223
Development costs during the period	55,196
Changes in estimated future development costs	(251,484)
Revisions of previous quantity estimates	98,283
Sales of reserves in place	(315,758)
Purchase of reserves in place	604,366
Accretion of discount before income taxes	69,615
Changes in timing and other	(33,625)
Net change in income taxes	—
Net change	$ 556,126

Costs not subject to amortization

The following table summarizes the categories of costs comprising the amount of unproved properties not subject to amortization by the year in which such costs were incurred. There are no individually significant properties or significant development projects included in costs not being amortized. The majority of the evaluation activities are expected to be completed within one to seven years.

(in thousands)	Total	2015	2014	2013	2012 and prior
Property acquisition costs	$ 75,019	$ 11,121	$ 7,862	$ 12,403	$ 43,633
Exploration and development	12,100	12,100	—	—	—
Capitalized interest	28,258	8,464	8,604	5,384	5,806
Total	$ 115,377	$ 31,685	$ 16,466	$ 17,787	$ 49,439

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

None.

Item 9A. Controls and Procedures

Disclosure controls and procedures. Pursuant to Rule 13a-15(b) under the Exchange Act, EXCO's management has evaluated, under the supervision and with the participation of 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) of the Exchange Act), as of the end of the period covered by this report. Based on this evaluation, our principal executive officer and principal financial officer have concluded that EXCO's disclosure controls and procedures were effective as of December 31, 2015 to ensure that information that is required to be disclosed by EXCO in the reports it files or submits under the Exchange Act is (i) recorded, processed, summarized and reported, within the time periods specified in the SEC's rules and forms and (ii) accumulated and communicated to EXCO's management, including our principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

Management's report on internal control over financial reporting. EXCO's management is responsible for establishing and maintaining adequate internal control over financial reporting (as defined in Rule 13a-15(f) or 15d-15(f) of the Exchange Act). Management assessed the effectiveness of our internal control over financial reporting as of December 31, 2015, using criteria established in *Internal Control-Integrated Framework (2013)* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Even an effective internal control system, no matter how well designed, has inherent limitations, including the possibility of human error and circumvention or overriding of controls and therefore can provide only reasonable assurance with respect to reliable financial reporting. Furthermore, the effectiveness of an internal control system in future periods can change with conditions. Management's annual report of internal control over financial reporting and the audit report on our internal control over financial reporting of our independent registered public accounting firm, KPMG LLP, are included in Item 8 of this Annual Report on Form 10-K and are incorporated by reference herein.

Changes in internal control over financial reporting. There were no changes in EXCO's internal control over financial reporting that occurred during the quarter ended December 31, 2015 that have materially affected, or are reasonably likely to materially affect, EXCO's internal control over financial reporting.

Item 9B. Other Information

None.

PART III

Item 10. Directors, Executive Officers and Corporate Governance

The information required in response to this Item 10 is incorporated herein by reference to our Definitive Proxy Statement to be filed with the SEC pursuant to Regulation 14A of the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 11. Executive Compensation

The information required in response to this Item 11 is incorporated herein by reference to our Definitive Proxy Statement to be filed with the SEC pursuant to Regulation 14A of the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

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

The information required in response to this Item 12 is incorporated herein by reference to our Definitive Proxy Statement to be filed with the SEC pursuant to Regulation 14A of the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 13. Certain Relationships and Related Transactions and Director Independence

The information required in response to this Item 13 is incorporated herein by reference to our Definitive Proxy Statement to be filed with the SEC pursuant to Regulation 14A of the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

Item 14. Principal Accountant Fees and Services

The information required in response to this Item 14 is incorporated herein by reference to our Definitive Proxy Statement to be filed with the SEC pursuant to Regulation 14A of the Exchange Act not later than 120 days after the end of the fiscal year covered by this Annual Report on Form 10-K.

PART IV

Item 15. Exhibits and Financial Statement Schedules

(a)(1) See Part II, Item 8. Financial Statements and Supplementary Data of this Annual Report on Form 10-K.

(a)(2) None.

(a)(3) See "Index to Exhibits" for a description of our exhibits.

(b) See "Index to Exhibits" for a description of our exhibits.

(c) None.

SIGNATURES

Pursuant to the requirements 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.

Date: March 2, 2016

EXCO RESOURCES, INC.
(Registrant)

/s/ Harold L. Hickey

Harold L. Hickey
Chief Executive Officer and President
(Principal Executive Officer)

EXCO RESOURCES, INC.
(Registrant)

Date: March 2, 2016

/s/ Harold L. Hickey

Harold L. Hickey
Chief Executive Officer and President
(Principal Executive Officer)

/s/ Richard A. Burnett

Richard A. Burnett
Vice President, Chief Financial Officer
and Chief Accounting Officer
(Principal Financial Officer and Principal Accounting Officer)

/s/ C. John Wilder

C. John Wilder
Executive Chairman

/s/ Jeffrey D. Benjamin

Jeffrey D. Benjamin
Director

/s/ B. James Ford

B. James Ford
Director

/s/ Samuel A. Mitchell

Samuel A. Mitchell
Director

/s/ Wilbur L. Ross, Jr.

Wilbur L. Ross, Jr.
Director

/s/ Jeffrey S. Serota

Jeffrey S. Serota
Director

/s/ Robert L. Stillwell

Robert L. Stillwell
Director

INDEX TO EXHIBITS

Exhibit Number	Description of Exhibits
2.1	Haynesville Purchase and Sale Agreement, by and among Chesapeake Louisiana, L.P., Empress, L.L.C., Empress Louisiana Properties, L.P. and EXCO Operating Company, LP, dated July 2, 2013, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2013 filed on October 30, 2013 and incorporated by reference herein.
2.2	Eagle Ford Purchase and Sale Agreement, by and between Chesapeake Exploration, L.L.C. and EXCO Operating Company, LP, dated July 2, 2013, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended September 30, 2013 filed on October 30, 2013 and incorporated by reference herein.
2.3	Contribution Agreement, by and among BG US Gathering Company, LLC, EXCO Operating Company, LP and Azure Midstream Holdings LLC, dated as of October 16, 2013, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 16, 2013 and filed on October 22, 2013 and incorporated by reference herein.
2.4	Purchase Agreement, dated October 6, 2014, by and among EXCO Resources, Inc., a Texas corporation, EXCO Operating Company, LP, a Delaware limited partnership, EXCO Holding MLP, Inc., a Texas corporation, HGI Energy Holdings, LLC, a Delaware limited liability company, Compass Production Services, LLC, a Delaware limited liability company, and Compass Energy Operating, LLC, a Delaware limited liability company, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 6, 2014 and filed on October 10, 2014 and incorporated by reference herein.
3.1	Amended and Restated Certificate of Formation of EXCO Resources, Inc., as amended through November 16, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 16, 2015 and filed on November 17, 2015 and incorporated by reference herein.
3.2	Third Amended and Restated Bylaws of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 8, 2015 and filed on September 9, 2015 and incorporated by reference herein.
4.1	Indenture, dated September 15, 2010, by and between EXCO Resources, Inc. and Wilmington Trust Company, as trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated September 10, 2010 and filed on September 15, 2010 and incorporated by reference herein.
4.2	First Supplemental Indenture, dated September 15, 2010, by and among EXCO Resources, Inc., certain of its subsidiaries and Wilmington Trust Company, as trustee, including the form of 7.500% Senior Notes due 2018, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated September 10, 2010 and filed on September 15, 2010 and incorporated by reference herein.
4.3	Second Supplemental Indenture, dated as of February 12, 2013, by and among EXCO Resources, Inc., EXCO/ HGI JV Assets, LLC, EXCO Holding MLP, Inc. and Wilmington Trust Company, as trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 12, 2013 and filed on February 19, 2013 and incorporated by reference herein.
4.4	Third Supplemental Indenture, dated April 16, 2014, by and among EXCO Resources, Inc., certain of its subsidiaries and Wilmington Trust Company, as trustee, including the form of 8.500% Senior Notes due 2022, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated April 11, 2014 and filed on April 16, 2014 and incorporated by reference herein.
4.5	Fourth Supplemental Indenture, dated May 12, 2014, by and among EXCO Resources, Inc., EXCO Land Company, LLC and Wilmington Trust Company, as trustee, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2014 and filed on July 30, 2014 and incorporated by reference herein.
4.6	Fifth Supplemental Indenture, dated as of November 24, 2015, by and among EXCO Resources, Inc., certain of its subsidiaries, and Wilmington Trust Company, as trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 24, 2015 and filed on November 25, 2015 and incorporated by reference herein.

4.7	Specimen Stock Certificate for EXCO's common stock, filed as an Exhibit to EXCO's Registration Statement on Form S-3 (File No. 333-192898), filed on December 17, 2013 and incorporated by reference herein.
4.8	First Amended and Restated Registration Rights Agreement dated as of December 30, 2005, by and among EXCO Holdings Inc. and the Initial Holders (as defined therein), filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-l (File No. 333-129935), filed on January 6, 2006 and incorporated by reference herein.
4.9	Registration Rights Agreement, dated March 28, 2007, by and among EXCO Resources, Inc. and the other parties thereto with respect to the 7.0% Cumulative Convertible Perpetual Preferred Stock and the Hybrid Preferred Stock, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743) dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
4.10	Registration Rights Agreement, dated March 28, 2007, by and among EXCO Resources, Inc. and the other parties thereto with respect to the Hybrid Preferred Stock, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743) dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
4.11	Joinder Agreement to Registration Rights Agreement, dated January 17, 2014, by and among EXCO Resources, Inc. and WLR IV Exco AIV One, L.P., WLR IV Exco AIV Two, L.P., WLR IV Exco AIV Three, L.P., WLR IV Exco AIV Four, L.P., WLR IV Exco AIV Five, L.P., WLR IV Exco AIV Six, L.P., WLR Select Co-Investment XCO AIV, L.P., WLR/GS Master Co-Investment XCO AIV, L.P. and WLR IV Parallel ESC, L.P, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 17, 2014 and filed on January 21, 2014 and incorporated by reference herein.
4.12	Joinder Agreement to Registration Rights Agreement, dated January 17, 2014, by and among EXCO Resources, Inc. and Advent Syndicate 780, Clearwater Insurance Company, Northbridge General Insurance Company, Odyssey Reinsurance Company, Clearwater Select Insurance Company, Riverstone Insurance Limited, Zenith Insurance Company and Fairfax Master Trust Fund, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated January 17, 2014 and filed on January 21, 2014 and incorporated by reference herein.
10.1	Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.2	Form of Incentive Stock Option Agreement for the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.3	Form of Nonqualified Stock Option Agreement for the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.4	Form of Restricted Stock Award Agreement for the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated August 4, 2011 and filed on August 10, 2011 and incorporated by reference herein.*
10.5	Form of Restricted Stock Award Agreement for Named Executive Officers for the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2015 filed on July 27, 2015 and incorporated by reference herein.*
10.6	Form of Performance-Based Restricted Stock Unit Agreement for the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 30, 2014 and filed on July 3, 2014 and incorporated by reference herein.*
10.7	Form of Performance-Based Share Unit Agreement for the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated July 1, 2015 and filed on July 8, 2015 and incorporated by reference herein.*
10.8	Form of Performance-Based Share Unit Agreement for Named Executive Officers for the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated July 1, 2015 and filed on July 8, 2015 and incorporated by reference herein.*

10.9	Fourth Amended and Restated EXCO Resources, Inc. Severance Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 16, 2011 and filed on March 22, 2011 and incorporated by reference herein.*
10.10	Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated November 14, 2007 and filed on November 16, 2007 and incorporated by reference herein.*
10.11	Amendment Number One to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., filed as an Exhibit to EXCO's Annual Report on Form 10-K (File No. 001-32743) for 2009 filed on February 24, 2010 and incorporated by reference herein.*
10.12	Amendment Number Two to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., effective as of May 22, 2014, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 22, 2014 and filed on May 29, 2014 and incorporated by reference herein.*
10.13	Amendment Number Three to the Amended and Restated 2007 Director Plan of EXCO Resources, Inc., effective as of December 4, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated December 4, 2015 and filed on December 10, 2015 and incorporated by reference herein.*
10.14	Letter Agreement, dated March 28, 2007, with OCM Principal Opportunities Fund IV, L.P. and OCM EXCO Holdings, LLC, filed as an Exhibit to EXCO's Form 8-K (File No. 001-32743), dated March 28, 2007 and filed on April 2, 2007 and incorporated by reference herein.
10.15	Amendment Number One to the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, filed as an exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 4, 2009 and filed on June 10, 2009 and incorporated by reference herein.*
10.16	Amendment Number Two to the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, dated as of October 6, 2011, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 6, 2011 and filed on October 7, 2011 and incorporated by reference herein.*
10.17	Amendment Number Three to the EXCO Resources, Inc. Amended and Restated 2005 Long-Term Incentive Plan, dated as of June 11, 2013, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated June 11, 2013 and filed on June 12, 2013 and incorporated by reference herein.*
10.18	Form of Restricted Stock Award Agreement, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2013 filed on August 7, 2013 and incorporated by reference herein.*
10.19	Joint Development Agreement, dated August 14, 2009, by and among BG US Production Company, LLC, EXCO Operating Company, LP and EXCO Production Company, LP, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated August 11, 2009 and filed on August 17, 2009 and incorporated by reference herein.
10.20	Amendment to Joint Development Agreement, dated February 1, 2011, by and among BG US Production Company, LLC and EXCO Operating Company, LP, filed as an Exhibit to EXCO's Annual Report on Form 10-K for 2010 filed February 24, 2011 and incorporated by reference herein.
10.21	Amendment to Joint Development Agreement, dated October 14, 2014, by and among BG US Production Company, LLC and EXCO Operating Company, LP, filed as an Exhibit to EXCO's Annual Report on 10-K for 2014 Filed on February 25, 2015 and incorporated in reference herein.
10.22	Joint Development Agreement, dated as of June 1, 2010, by and among EXCO Production Company (PA), LLC, EXCO Production Company (WV), LLC, BG Production Company, (PA), LLC, BG Production Company, (WV), LLC and EXCO Resources (PA), LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.23	Amendment to Joint Development Agreement, dated February 4, 2011, by and among EXCO Production Company (PA), LLC, EXCO Production Company (WV), LLC, BG Production Company, (PA), LLC, BG

Production Company, (WV), LLC and EXCO Resources (PA), LLC, filed as an Exhibit to EXCO's Annual Report on Form 10-K (File No. 001-32743) for 2010 filed February 24, 2011 and incorporated by reference herein.

10.24	Amendment to Joint Development Agreement, dated October 14, 2014, by and among EXCO Production Company (PA), LLC, EXCO Production Company (WV), LLC, BG Production Company, (PA), LLC, BG Production Company, (WV), LLC and EXCO Resources (PA), LLC, filed as an Exhibit to EXCO's Annual Report on 10-K for 2014 Filed on February 25, 2015 and incorporated by reference herein.
10.25	Second Amended and Restated Limited Liability Company Agreement of EXCO Resources (PA), LLC, dated June 1, 2010, by and among EXCO Holding (PA), Inc., BG US Production Company, LLC and EXCO Resources (PA), LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.26	Amendment to Second Amended and Restated Limited Liability Company Agreement of EXCO Resources (PA), LLC, dated October 14, 2014, by and among EXCO Holding (PA), Inc., BG US Production Company, LLC and EXCO Resources (PA), LLC, filed as an Exhibit to EXCO's Annual Report on 10-K for 2014 Filed on February 25, 2015 and incorporated by reference herein.
10.27	Second Amended and Restated Limited Liability Company Agreement of Appalachia Midstream, LLC, dated June 1, 2010, by and among EXCO Holding (PA), Inc., BG US Production Company, LLC and Appalachia Midstream, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.28	Amendment to Second Amended and Restated Limited Liability Company Agreement of Appalachia Midstream, LLC (n/k/a EXCO Appalachia Midstream, LLC), dated October 14, 2014, by and among EXCO Holding (PA), Inc., BG US Production Company, LLC and EXCO Appalachia Midstream, LLC, filed as an Exhibit to EXCO's Annual Report on 10-K for 2014 Filed on February 25, 2015 and incorporated by reference herein.
10.29	Letter Agreement, dated June 1, 2010 and effective as of May 9, 2010, by and between EXCO Holding (PA), Inc. and BG US Production Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.30	Guaranty, dated May 9, 2010, by BG Energy Holdings Limited in favor of EXCO Holding (PA), Inc., EXCO Production Company (PA), LLC and EXCO Production Company (WV), LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.31	Performance Guaranty, dated May 9, 2010, by EXCO Resources, Inc. in favor of BG US Production Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.32	Guaranty, dated June 1, 2010, by BG North America, LLC in favor of (i) EXCO Production Company (PA), LLC, EXCO Production Company (WV), LLC and EXCO Resources (PA), LLC; and (ii) EXCO Resources (PA), LLC and EXCO Holding (PA), Inc, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.33	Guaranty, dated June 1, 2010, by EXCO Resources, Inc., in favor of: (i) BG Production Company (PA), LLC, BG Production Company (WV), LLC and EXCO Resources (PA), LLC; and (ii) EXCO Resources (PA), LLC and BG US Production Company, LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated June 1, 2010 and filed on June 7, 2010 and incorporated by reference herein.
10.34	Transition Consulting Agreement, dated February 28, 2013, by and between EXCO Resources, Inc. and Stephen F. Smith, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated February 28, 2013 and filed on March 6, 2013 and incorporated by reference herein.*
10.35	Amended and Restated Credit Agreement, dated as of July 31, 2013, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lender parties thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Form 8-K, dated as of August 19, 2013 and filed on August 23, 2013 and incorporated by reference herein.

10.36	First Amendment to Amended and Restated Credit Agreement, dated as of August 28, 2013, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lender parties thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Form 8-K, dated as of August 28, 2013 and filed on September 4, 2013 and incorporated by reference herein.
10.37	Second Amendment to Amended and Restated Credit Agreement, dated as of July 14, 2014, by and among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Form 8-K, dated as of July 14, 2014 and filed on July 18, 2014 and incorporated by reference herein.
10.38	Third Amendment to Amended and Restated Credit Agreement, dated as of October 21, 2014, by and among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the Lenders party thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated October 21, 2014 and filed on October 27, 2014 and incorporated by reference herein.
10.39	Fourth Amendment to Amended and Restated Credit Agreement, dated as of February 6, 2015, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lender parties thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report Form 8-K, dated as of February 6, 2015 and filed on February 12, 2015 and incorporated by reference herein.
10.40	Fifth Amendment to Amended and Restated Credit Agreement, dated July 27, 2015, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lender parties thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of July 27, 2015 and filed July 28, 2015 and incorporated by reference herein.
10.41	Sixth Amendment to Amended and Restated Credit Agreement, dated as of October 19, 2015, among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lender parties thereto, and JPMorgan Chase Bank, N.A., as Administrative Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of October 19, 2015 and filed on October 22, 2015 and incorporated by reference herein.
10.42	Term Loan Credit Agreement, dated as of October 19, 2015, by and among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, Hamblin Watsa Investment Counsel Ltd., as Administrative Agent, and Wilmington Trust, National Association, as Collateral Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of October 19, 2015 and filed on October 22, 2015 and incorporated by reference herein.
10.43	Term Loan Credit Agreement, dated as of October 19, 2015, by and among EXCO Resources, Inc., as Borrower, certain subsidiaries of Borrower, as Guarantors, the lenders party thereto, and Wilmington Trust, National Association, as Administrative Agent and Collateral Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of October 19, 2015 and filed on October 22, 2015 and incorporated by reference herein.
10.44	Form of Joinder Agreement to Term Loan Credit Agreement, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of November 4, 2015 and filed on November 11, 2015 and incorporated by reference herein.
10.45	Intercreditor Agreement, dated as of October 26, 2015, by and among EXCO Resources, Inc., JPMorgan Chase Bank, N.A., as Priority Lien Agent, and Wilmington Trust, National Association, as Second Lien Collateral Agent, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of October 26, 2015 and filed on October 27, 2015 and incorporated by reference herein.
10.46	Intercreditor Joinder, dated as of October 26, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of October 26, 2015 and filed on October 27, 2015 and incorporated by reference herein.
10.47	Collateral Trust Agreement, dated as of October 26, 2015, by and among EXCO Resources, Inc., the grantors and guarantors from time to time party thereto, Hamblin Watsa Investment Counsel Ltd., as Administrative Agent of the second lien credit agreement, the other parity lien debt representatives from time to time party thereto, and Wilmington Trust, National Association, as Collateral Trustee, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of October 26, 2015 and filed on October 27, 2015 and incorporated by reference herein.
10.48	Collateral Trust Joinder, dated as of October 26, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated as of October 26, 2015 and filed on October 27, 2015 and incorporated by reference herein.

10.49 Form of Purchase Agreement, filed as an Exhibit to EXCO's Form 8-K, dated as of October 19, 2015 and filed on October 22, 2015 and incorporated by reference herein.

10.50 Form of Follow-on Purchase Agreement, filed as an Exhibit to EXCO's Form 8-K, dated as of October 30, 2015 and filed on November 2, 2015 and incorporated by reference herein.

10.51 Participation Agreement, dated July 31, 2013, among Admiral A Holding L.P., Admiral B Holding L.P. and EXCO Operating Company, LP, filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2013 filed on August 7, 2013 and incorporated by reference herein.

10.52 Amendment No. 1 to Participation Agreement, dated April 17, 2014, among EXCO Operating Company, LP, Admiral A Holding L.P. and Admiral B Holding L.P., filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2014 and filed on July 30, 2014 and incorporated by reference herein.

10.53 Amendment No. 2 to Participation Agreement, dated June 1, 2015, among EXCO Operating Company, LP, Admiral A Holding L.P., TE Admiral A Holding L.P. and Colt A Holding L.P., filed as an Exhibit to EXCO's Quarterly Report on Form 10-Q for the Quarter Ended June 30, 2015 filed on July 27, 2015 and incorporated by reference herein.

10.54 Form of Director Indemnification Agreement, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 10, 2010 and filed on November 12, 2010 and incorporated by reference herein.

10.55 MVC Letter Agreement, dated November 15, 2013, among BG US Production Company, LLC, BG US Gathering Company, LLC, EXCO Operating Company, LP, Azure Midstream Energy LLC (formerly known as TGGT Holdings, LLC) and TGG Pipeline, Ltd, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated November 15, 2013 and filed on November 21, 2013 and incorporated by reference herein.

10.56 Letter Agreement, dated March 28, 2014, by and among EXCO Resources, Inc. and Ares Corporate Opportunities Fund, L.P., ACOF EXCO L.P, ACOF EXCO 892 Investors, L.P., Ares Corporate Opportunities Fund II, L.P., Ares EXCO, L.P. and Ares EXCO 892 Investors, L.P., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 27, 2014 and filed on April 1, 2014 and incorporated by reference herein.

10.57 EXCO Resources, Inc. 2014 Management Incentive Plan, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2014 and filed on April 25, 2014 and incorporated by reference herein.*

10.58 Amendment Number One to the EXCO Resources, Inc. Management Incentive Plan, effective as of September 1, 2014, filed as an Exhibit to Amendment No. 1 to EXCO's Current Report on Form 8-K/A, dated August 6, 2014 and filed on September 5, 2014 and incorporated by reference herein.*

10.59 EXCO Resources, Inc. 2015 Management Incentive Plan, dated March 4, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 4, 2015 and filed on March 10, 2015 and incorporated by reference herein.*

10.60 Retention Agreement, dated May 14, 2015, by and between Harold H. Jameson and EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 14, 2015 and filed on May 20, 2015 and incorporated by reference herein.*

10.61 Amended and Restated Retention Agreement, dated May 14, 2015, by and between William L. Boeing and EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 14, 2015 and filed on May 20, 2015 and incorporated by reference herein.*

10.62 Amended and Restated Retention Agreement, dated May 14, 2015, by and between Richard A. Burnett and EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 14, 2015 and filed on May 20, 2015 and incorporated by reference herein.*

10.63 Amended and Restated Retention Agreement, dated May 14, 2015, by and between Harold L. Hickey and EXCO Resources, Inc., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 14, 2015 and filed on May 20, 2015 and incorporated by reference herein.*

10.64	Services and Investment Agreement, dated as of March 31, 2015, by and among EXCO Resources, Inc. and Energy Strategic Advisory Services LLC, filed as an Exhibit to Amendment No. 1 to EXCO's Current Report on Form 8-K/A, dated March 31, 2015 and filed on May 26, 2015 and incorporated by reference herein.
10.65	Acknowledgement of Amendment to Services and Investment Agreement, dated as of May 26, 2015, by and between EXCO Resources, Inc. and Energy Strategic Advisory Services LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated May 26, 2015 and filed on June 1, 2015 and incorporated by reference herein.
10.66	Amendment No. 2 to Services and Investment Agreement, dated as of September 8, 2015, by and between EXCO Resources, Inc. and Energy Strategic Advisory Services LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 8, 2015 and filed on September 9, 2015 and incorporated by reference herein.
10.67	Nomination Letter Agreement, dates as of September 8, 2015, by and between EXCO Resources, Inc. and Energy Strategic Advisory Services LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated September 8, 2015 and filed on September 9, 2015 and incorporated by reference herein.
10.68	Warrant, dated as of March 31, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 31, 2015 and filed on April 2, 2015 and incorporated by reference herein.
10.69	Warrant, dated as of March 31, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 31, 2015 and filed on April 2, 2015 and incorporated by reference herein.
10.70	Warrant, dated as of March 31, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 31, 2015 and filed on April 2, 2015 and incorporated by reference herein.
10.71	Warrant, dated as of March 31, 2015, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated March 31, 2015 and filed on April 2, 2015 and incorporated by reference herein.
10.72	Registration Rights Agreement, dated as of April 21, 2015, by and between EXCO Resources, Inc. and Energy Strategic Advisory Services LLC, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2015 and filed on April 27, 2015 and incorporated by reference herein.
10.73	Registration Rights Waiver, dated as of April 10, 2015, by and among EXCO Resources, Inc. and Jeffrey D. Benjamin, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2015 and filed on April 27, 2015 and incorporated by reference herein.
10.74	Registration Rights Waiver, dated as of April 10, 2015, by and among EXCO Resources, Inc. and Robert L. Stillwell, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2015 and filed on April 27, 2015 and incorporated by reference herein.
10.75	Registration Rights Waiver, dated as of April 10, 2015, by and among EXCO Resources, Inc. and Harold L. Hickey, filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2015 and filed on April 27, 2015 and incorporated by reference herein.
10.76	Registration Rights Waiver, dated as of April 13, 2015, by and among EXCO Resources, Inc. and Advent Capital (No. 3) Limited, Clearwater Insurance Company, Clearwater Select Insurance Company, Fairfax Financial Holdings Master Trust Fund, Northbridge General Insurance Company, Odyssey Reinsurance Company, RiverStone Insurance Limited, Zenith Insurance Company and Hamblin Watsa Investment Counsel, Ltd., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2015 and filed on April 27, 2015 and incorporated by reference herein.
10.77	Registration Rights Waiver, dated as of April 13, 2015, by and among EXCO Resources, Inc. and OCM EXCO Holdings, LLC, OCM Principal Opportunities Fund IV Delaware, L.P., OCM Principal Opportunities Fund III, L.P., OCM Principal Opportunities Fund IIIA, L.P. and Oaktree Value Opportunities Fund Holdings, L.P., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2015 and filed on April 27, 2015 and incorporated by reference herein.
10.78	Registration Rights Waiver, dated as of April 21, 2015, by and among EXCO Resources, Inc. and WLR IV Exco AIV One, L.P., WLR IV Exco AIV Two, L.P., WLR IV Exco AIV Three, L.P., WLR IV Exco AIV Four, L.P., WLR IV Exco AIV Five, L.P., WLR IV Exco AIV Six, L.P., WLR Select Co-Investment XCO AIV, L.P., WLR/

GS Master Co-Investment XCO AIV, L.P. and WLR IV Parallel ESC, L.P., filed as an Exhibit to EXCO's Current Report on Form 8-K, dated April 21, 2015 and filed on April 27, 2015 and incorporated by reference herein.

14.1	Code of Ethics for the Chief Executive Officer and Senior Financial Officers, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.2	Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Amendment No. 1 to its Registration Statement on Form S-1 (File No. 333-129935) filed January 6, 2006 and incorporated by reference herein.
14.3	Amendment No. 1 to EXCO Resources, Inc. Code of Business Conduct and Ethics for Directors, Officers and Employees, filed as an Exhibit to EXCO's Current Report on Form 8-K (File No. 001-32743), dated November 8, 2006 and filed on November 9, 2006 and incorporated by reference herein.
21.1	Subsidiaries of registrant, filed herewith.
23.1	Consent of KPMG LLP, filed herewith.
23.2	Consent of Lee Keeling and Associates, Inc., filed herewith.
23.3	Consent of Netherland, Sewell & Associates, Inc., filed herewith.
23.4	Consent of Ryder Scott Company, L.P., filed herewith.
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Principal Executive Officer of EXCO Resources, Inc., filed herewith.
31.2	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 of Principal Financial Officer of EXCO Resources, Inc., filed herewith.
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 of Principal Executive Officer and Principal Financial Officer of EXCO Resources, Inc., filed herewith.
99.1	2015 Report of Lee Keeling and Associates, Inc., filed herewith.
99.2	2015 Report of Netherland, Sewell & Associates, Inc., filed herewith.
99.3	2015 Report of Ryder Scott Company, L.P., filed herewith.
101.INS	XBRL Instance Document.
101.SCH	XBRL Taxonomy Extension Schema Document.
101.CAL	XBRL Taxonomy Calculation Linkbase Document.
101.DEF	XBRL Taxonomy Definition Linkbase Document.
101.LAB	XBRL Taxonomy Label Linkbase Document.
101.PRE	XBRL Taxonomy Presentation Linkbase Document.
*	These exhibits are management contracts.

SEC AND NYSE CERTIFICATIONS

The Form 10-K, included herein, which was filed by the company with the SEC for the fiscal year ending December 31, 2015, include, as exhibits, the certifications of our principal executive officer and principal financial officer required to be filed with the SEC. Our principal executive officer also filed his 2015 annual certification with the NYSE confirming that the company has complied with the NYSE corporate governance listing standards.

DIRECTORS

C. JOHN WILDER
Executive Chairman –
EXCO Resources, Inc.
Executive Chairman –
Bluescape Resources Company LLC

JEFFREY D. BENJAMIN [1, 2, 3]
Senior Advisor –
Cyrus Capital Partners, LP

B. JAMES FORD [2, 3]
Senior Advisor –
Oaktree Capital Management, L.P.

SAMUEL A. MITCHELL
Managing Director –
Hamblin Watsa Investment Counsel

WILBUR L. ROSS, JR. [2, 3]
Chairman and Chief Strategy Officer –
WL Ross & Co. LLC

JEFFREY S. SEROTA [1, 2, 3]
Independent Director

ROBERT L. STILLWELL [1, 2, 3]
Retired General Counsel –
BP Capital LP

[1] Audit Committee Member
[2] Compensation Committee Member
[3] Nominating and Corporate Governance Committee Member

OFFICERS

HAROLD L. HICKEY
Chief Executive Officer
and President

WILLIAM L. BOEING
Vice President, General Counsel
and Secretary

RICHARD A. BURNETT
Vice President, Chief Financial Officer
and Chief Accounting Officer

HAROLD H. JAMESON
Vice President
and Chief Operating Officer

W. JUSTIN CLARKE
Assistant General Counsel,
Chief Compliance Officer
and Assistant Secretary

RONALD G. EDELEN
Vice President of Supply Chain

STEVE L. ESTES
Vice President of Marketing

DANIEL W. HIGDON
Vice President of Land

CHRISTOPHER C. PERACCHI
Vice President of Finance
and Investor Relations, and Treasurer

STEPHEN E. PUCKETT
Vice President of Engineering and Geoscience

SHAREHOLDER INFORMATION

Shareholder Relations
Christopher C. Peracchi
Vice President of Finance and
Investor Relations,
and Treasurer
214.368.2084

NYSE Symbol
XCO – Common Stock

Auditors
KPMG LLP
717 North Harwood St., Suite 3100
Dallas, Texas 75201

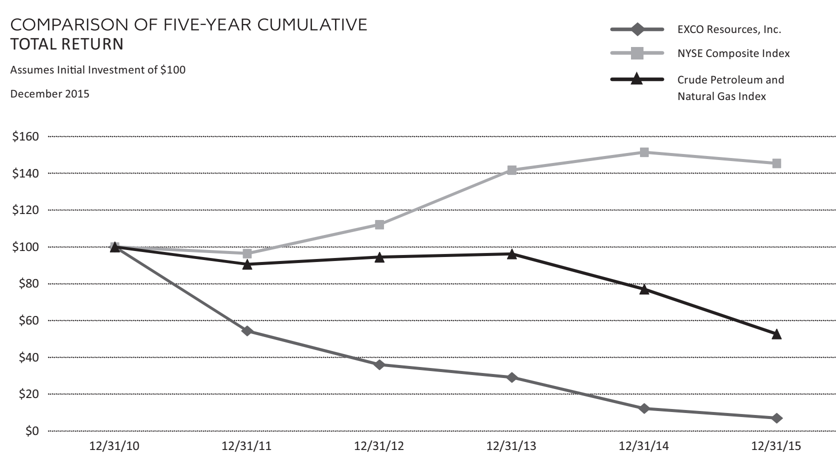
Legal Counsel
Haynes and Boone, LLP
2323 Victory Ave., Suite 700
Dallas, Texas 75219

Annual Meeting
The 2016 Annual Meeting
of Shareholders will be held
on May 19, 2016
at 10:00 a.m. local time at:

EXCO Resources, Inc.
12377 Merit Dr.
First Floor Conference Center
Dallas, Texas 75251

Stock Transfer Agent
Continental Stock Transfer &
Trust Company
Communications concerning
transfer or exchange
requirements, lost certificates,
shareholdings or changes of address
should be directed to:
17 Battery Place, 8th Floor
New York, New York 10004
212.509.4000

Number of Common Shareholders
27,441
(As of March 2, 2016)



The graph to the right compares the cumulative total return (what $100 invested on December 31, 2010 would be worth on December 31, 2015) on the Company's common stock with the cumulative total return on the NYSE Composite Index and the Crude Petroleum and Natural Gas SIC Code Index.

These historical comparisons are not a forecast of the future performance of our common stock or the referenced indexes.

	PERIOD ENDING					
	12.31.10	12.31.11	12.31.12	12.31.13	12.31.14	12.31.15
EXCO Resources, Inc.	$100.00	$54.41	$ 36.05	$ 29.13	$ 12.26	$ 7.01
NYSE Composite Index	$100.00	$96.43	$112.10	$141.70	$151.44	$145.40
Crude Petroleum and Natural Gas Index	$100.00	$90.63	$ 94.48	$ 96.23	$ 77.05	$ 52.75