

CHESAPEAKE GRANITE WASH TRUST
Form 10-K
March 30, 2017

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, 2016

Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from _____ to _____.

Commission File No. 001-35343

Chesapeake Granite Wash Trust
(Exact name of registrant as specified in its charter)

Delaware 45-6355635
(State or other jurisdiction of incorporation or organization) (I.R.S. Employer Identification No.)

The Bank of New York Mellon

Trust Company, N.A., Trustee

Global Corporate Trust

919 Congress Avenue

Austin, Texas

(Address of principal executive offices)

(512) 236-6555

(Registrant's telephone number, including area code)

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

Title of Each Class	Name of Each Exchange on which Registered
---------------------	---

Common Units Representing Beneficial Interests	New York Stock Exchange
--	-------------------------

Securities registered pursuant to Section 12(g) of the Act: None

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

Yes No

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

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

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (§232.405 of this chapter) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes No

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K (§ 229.405 of this chapter) is not contained herein, and will not be contained, to the best of the registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K.

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

Large accelerated filer Accelerated filer Non-accelerated filer Smaller reporting company

(Do not check if a smaller reporting company)

Edgar Filing: CHESAPEAKE GRANITE WASH TRUST - Form 10-K

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

The aggregate market value of the 23,000,000 Common Units representing beneficial interests in Chesapeake Granite Wash Trust held by non-affiliates of the registrant, computed using the closing sale price of \$2.10 on June 30, 2016, was approximately \$48 million.

As of March 29, 2017, 35,062,500 Common Units and 11,687,500 Subordinated Units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

Listed below is the only document parts of which are incorporated herein by reference and the parts of this Annual Report into which the document is incorporated:

None

CHESAPEAKE GRANITE WASH TRUST
 2016 ANNUAL REPORT ON FORM 10-K
 TABLE OF CONTENTS

	Page
PART I	
Item 1. Business	<u>1</u>
Item 1A. Risk Factors	22
Item 1B. Unresolved Staff Comments	36
Item 2. Properties	36
Item 3. Legal Proceedings	37
Item 4. Mine Safety Disclosures	37
PART II	
Item 5. Market for Units of the Trust, Related Unitholder Matters and Trust Purchases of Units	38
Item 6. Selected Financial Data	39
Item 7. Trustee's Discussion and Analysis of Financial Condition and Results of Operations	39
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	46
Item 8. Financial Statements and Supplementary Data	47
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	66
Item 9A. Controls and Procedures	66
Item 9B. Other Information	67
PART III	
Item 10. Directors, Executive Officers and Corporate Governance	68
Item 11. Executive Compensation	68
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	68
Item 13. Certain Relationships and Related Transactions and Director Independence	69
Item 14. Principal Accountant Fees and Services	70
PART IV	
Item 15. Exhibits, Financial Statement Schedules	72
Item 16. Form 10-K Summary	72

All references to “we,” “us,” “our,” or the “Trust” refer to Chesapeake Granite Wash Trust. The royalty interests conveyed on November 16, 2011 by Chesapeake from its interests in certain properties in the Colony Granite Wash formation in Oklahoma and held by the Trust are referred to as the “Royalty Interests.” References to “Chesapeake” refer to Chesapeake Energy Corporation and, where the context requires, its subsidiaries.

DISCLOSURES REGARDING FORWARD-LOOKING STATEMENTS

This Annual Report on Form 10-K ("Annual Report") includes "forward-looking statements" about the Trust and Chesapeake and other matters discussed herein that are subject to risks and uncertainties that are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995, and Section 21E of the Securities Exchange Act of 1934, as amended (the "Exchange Act"). All statements other than statements of historical fact included in this document, including, without limitation, statements under "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" in Item 7 of Part II and "Risk Factors" in Item 1A of Part I and elsewhere herein regarding the proved oil, natural gas and NGL reserves associated with the properties underlying the Royalty Interests, the Trust's or Chesapeake's future financial position, business strategy, budgets, projected costs and plans and objectives for future operations, information regarding target distributions, statements pertaining to future development activities and costs, statements regarding the number of development wells to be completed in future periods and information regarding production and reserve growth are forward-looking statements. Actual outcomes and results may differ materially from those projected. Our forward-looking statements are generally accompanied by words such as "estimate," "project," "predict," "believe," "expect," "anticipate," "potential," "could," "may," "plan," "goal," "assume," "target," "should," "intend" or other words that convey the uncertainty of future events or outcomes. These statements are based on certain assumptions made by the Trust, and by Chesapeake in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with such expectations and predictions is subject to a number of risks and uncertainties, including the risk factors discussed in Item 1A of Part I of this Annual Report, which could affect the future results of the energy industry in general, and the Trust and Chesapeake in particular, and could cause those results to differ materially from those expressed in such forward-looking statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on Chesapeake's business and the Trust. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. The Trustee relies on Chesapeake for information regarding the Royalty Interests, the Underlying Properties and Chesapeake itself. The Trust undertakes no obligation to publicly update or revise any forward-looking statements, except as required by applicable law.

GLOSSARY OF CERTAIN TERMS

In this Annual Report, the following terms have the meanings specified below. Other terms are defined in the text of this Annual Report.

AMI. The area of mutual interest, or AMI, lies within Washita County in western Oklahoma and is limited to the Colony Granite Wash formation in the area identified below, consisting of approximately 40,500 gross acres (26,400 net acres) held by Chesapeake as of December 31, 2016.

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

Boe. Barrel of oil equivalent.

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

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

Condensate. A mixture of hydrocarbons that exists in the gaseous phase at the original reservoir temperature and pressure, but that, when produced, is in the liquid phase at surface pressure and temperature.

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

Developed Reserves. Developed reserves are reserves of any category that can be expected to be recovered (a) 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 (b) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

Development Area. The sections adjacent to governmental sections in the AMI.

Development Costs. Costs incurred to obtain access to proved reserves and to provide facilities for extracting, treating, gathering and storing the oil and natural gas. More specifically, development costs, including depreciation and applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to (a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building and relocating public roads, gas lines and power lines, to the extent necessary in developing the proved reserves, (b) drill and equip Development Wells, development-type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment, and the wellhead assembly, (c) acquire, construct and install production facilities such as leases, flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems, and (d) provide improved recovery systems.

Development Well. A development well is 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. For the purposes of the Trust and as used herein, references to "Development Wells" refer to the 118 horizontal development wells that, since July 1, 2011, have been drilled on properties held by Chesapeake in the AMI and in which the Trust has received or will receive an interest.

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 Producing. The term economically producing, as it relates to a resource, means a resource which generates revenue that exceeds, or is reasonably expected to exceed, the costs of the operation. The value of the products that generate revenue is determined at the terminal point of oil and natural gas producing activities as defined in Rule 4-10(a)(16) of Regulation S-X under the Securities Act.

Estimated Future Net Revenues. Also referred to as "estimated future net cash flows." The result of applying current prices of oil, natural gas and NGL to estimated future production from oil, natural gas and NGL proved reserves, reduced by estimated future expenditures, based on current costs to be incurred, in developing and producing the proved reserves, excluding overhead.

Field. An area consisting of a single reservoir or multiple reservoirs all grouped on or related to the same individual geological structural feature and/or stratigraphic condition. There may be two or more reservoirs in a field which are separated vertically by intervening impervious strata, or laterally by local geologic barriers, or both. Reservoirs that are associated by being in overlapping or adjacent fields may be treated as a single or common operational field. The geological terms "structural feature" and "stratigraphic condition" are intended to identify localized geological features as opposed to the broader terms of basins, trends, provinces, plays or areas of interest.

GAAP. Generally accepted accounting principles in the United States.

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

IRS. The Internal Revenue Service of the United States federal government.

Mbbl. One thousand barrels of crude oil or other liquid hydrocarbons.

Mboe. One thousand barrels of oil equivalent.

Mcf. One thousand cubic feet.

Mmbtu. One million btus.

Mmcf. One million cubic feet.

Net Acres or Net Wells. The sum of the fractional working interest owned in gross acres or gross wells.

Net Revenue Interest. A share of production after all burdens, such as royalty and overriding royalty interests, have been deducted from the working interest.

Natural Gas Liquids (NGL). Those hydrocarbons in natural gas that are separated from the gas as liquids through the process of absorption, condensation, adsorption or other methods in gas processing or cycling plants. Natural gas liquids primarily include ethane, propane, butane, isobutene, pentane, hexane and natural gasoline.

NYMEX. New York Mercantile Exchange.

Plugging and Abandoning. Refers to the sealing off of fluids in the strata penetrated by a well so that the fluids

from one stratum will not escape into another or to the surface. Oklahoma regulations require plugging of abandoned wells.

Present Value or PV-10. When used with respect to oil, natural gas and NGL reserves, present value, or PV-10, means the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices calculated as the average oil and natural gas price during the preceding 12-month period prior to the end of the current reporting period, (determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period) and costs in effect at the determination date, without giving effect to non-property related expenses such as general and administrative expenses, debt service and future income tax expense or to depreciation, depletion and amortization, discounted using an annual discount rate of 10%. PV-10 is a non-GAAP financial measure and generally differs from the standardized measure of discounted net cash flows, or Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Because the Trust will not bear income tax expense, the PV-10 and Standardized Measure attributable to the Royalty Interests are the same.

Price Differential. The difference in the price of oil, natural gas or NGL received at the sales point and the NYMEX price.

Producing Well. As defined by the SEC, a producing well is a well that is found to be capable of producing hydrocarbons in sufficient quantities such that proceeds from the sale of such production exceeds production expenses and taxes. For the purposes of the Trust and as used herein, references to "Producing Wells" refer to the 69 existing horizontal wells in which Chesapeake conveyed an interest to the Trust effective as of July 1, 2011.

Production Expenses. Costs incurred to operate and maintain wells and related equipment and facilities, including depreciation and applicable operating costs of support equipment and facilities and other costs of operating and maintaining those wells and related equipment and facilities. They become part of the cost of oil, natural gas and NGL produced. Examples of production expenses (sometimes called lifting expenses) are:

- costs of labor to operate the wells and related equipment and facilities;
- repairs and maintenance;
- materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities;
- property taxes and insurance applicable to proved properties and wells and related equipment and facilities; and
- production taxes.

Some support equipment or facilities may serve two or more oil and natural gas producing activities and may also serve transportation, refining and marketing activities. To the extent that the support equipment and facilities are used in oil and gas producing activities, their depreciation and applicable operating costs become exploration, development or production expenses, as appropriate. Depreciation, depletion and amortization of capitalized acquisition, exploration, and development costs are not production expenses but also become part of the cost of oil and natural gas produced along with production (lifting) costs identified above.

Productive Well. A well that is not a dry well. Productive wells include producing wells and wells that are mechanically capable of production.

Prospectus. The Chesapeake Granite Wash Trust Prospectus dated November 10, 2011 and filed with the SEC on November 14, 2011 in connection with the initial public offering of the Trust's common units.

Proved Developed Reserves. Proved reserves that can be expected to be recovered 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.

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 a reservoir considered as proved

includes

(a) the area identified by drilling and limited by fluid contacts, if any, and (b) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible oil or natural gas on the basis of available geoscience and engineering data. In the absence of data on fluid contacts, proved quantities in a reservoir are limited by the lowest known hydrocarbons 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 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 that can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when (a) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (b) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is 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 the period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

Proved Undeveloped Reserves (PUDs). Proved reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion. Reserves on undrilled acreage are limited to those 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 proved undeveloped reserves only if a development plan has been adopted indicating that they are scheduled to be drilled within five years, unless specific circumstances justify a longer time. Estimates for proved undeveloped reserves are not attributed to any acreage for which an application of fluid injection or other improved recovery technique is contemplated, unless these 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.

Reserves. Estimated remaining quantities of oil and natural gas and related substances anticipated to be economically producible as of a given date, by application of development projects to known accumulations. In addition, there must exist, or there must be a reasonable expectation that there will exist, the legal right to produce or a revenue interest in the production, installed means of delivering oil and natural gas or related substances to market, and all permits and financing required to implement the project. Reserves should not be assigned to adjacent reservoirs isolated by major, potentially sealing, faults until those reservoirs are penetrated and evaluated as economically producible. Reserves should not be assigned to areas that are clearly separated from a known accumulation by a non-productive reservoir (i.e., absence of reservoir, structurally low reservoir, or negative test results). Such areas may contain prospective resources (i.e., potentially recoverable resources from undiscovered accumulations).

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.

Standardized Measure of Discounted Future Net Cash Flows. The discounted future net cash flows relating to proved reserves based on the prices used in estimating the proved reserves, year-end costs and statutory tax rates (adjusted for permanent differences) and a 10% annual discount rate. Because the Trust does not bear income taxes, PV-10 and standardized measure with respect to the Trust's Royalty Interests are the same.

Undeveloped Acreage. 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 which gives the owner the right to drill, produce and conduct operating activities on the property and a share of production.

PART I

ITEM 1. Business

Introduction

Chesapeake Granite Wash Trust is a statutory trust formed in June 2011 under the Delaware Statutory Trust Act pursuant to an initial trust agreement by and among Chesapeake, as Trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the "Trustee"), and The Corporation Trust Company, as Delaware Trustee (the "Delaware Trustee"). The Trust maintains its offices at the office of the Trustee, which is located at 919 Congress Avenue, Suite 500, Austin, Texas 78701, and the telephone number of the Trustee is (512) 236-6555.

The Trustee maintains a website for filings by the Trust with the Securities and Exchange Commission ("SEC"). Electronic filings by the Trust with the SEC are available free of charge through the Trust's website at www.chkgranitewashtrust.com or through the SEC's website at www.sec.gov. The Trust will also provide electronic and paper copies of its recent filings free of charge upon request to the Trustee. Documents and information on the Trust's website are not incorporated by reference herein.

General

The Trust was created to own the Royalty Interests for the benefit of Trust unitholders pursuant to a trust agreement dated as of June 29, 2011 and subsequently amended and restated as of November 16, 2011 by and among Chesapeake, Chesapeake Exploration, L.L.C., a wholly owned subsidiary of Chesapeake, the Trustee and the Delaware Trustee (the "Trust Agreement"). The Royalty Interests are derived from Chesapeake's interests in specified oil and natural gas properties located in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma (the "Underlying Properties"). Chesapeake conveyed the Royalty Interests to the Trust from Chesapeake's interests in the Producing Wells and the Development Wells.

The business and affairs of the Trust are managed by the Trustee. The Trust Agreement limits the Trust's business activities generally to owning the Royalty Interests and any activity reasonably related to such ownership, including activities required or permitted by the terms of the conveyances related to the Royalty Interests and derivative contracts between the Trust and its counterparty. The royalty interests in the Producing Wells (the "PDP Royalty Interest") entitle the Trust to receive 90% of the proceeds (exclusive of any production or development costs but after deducting certain post-production expenses and any applicable taxes) from the sales of oil, natural gas and NGL production attributable to Chesapeake's net revenue interest in the Producing Wells. The royalty interests in the Development Wells (the "Development Royalty Interest") entitle the Trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting certain post-production expenses and any applicable taxes) from the sales of oil, natural gas and NGL production attributable to Chesapeake's net revenue interest in the Development Wells.

Through an initial public offering in November 2011, the Trust sold to the public 23,000,000 common units, representing beneficial interests in the Trust, for cash proceeds of approximately \$409.7 million, net of offering costs. The Trust delivered the net proceeds of the initial public offering, along with 12,062,500 common units and 11,687,500 subordinated units, to certain wholly owned subsidiaries of Chesapeake in exchange for the conveyance of the Royalty Interests to the Trust. Upon completion of these transactions, there were 46,750,000 Trust units issued and outstanding, consisting of 35,062,500 common units and 11,687,500 subordinated units. The common units and subordinated units have identical rights and privileges, except with respect to their voting rights and rights to receive distributions as described below under Target Distributions and Subordination and Incentive Thresholds.

The subordinated units are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to provide a cash distribution on the common units that is no less than 80% of the target distribution set forth in the Trust Agreement for the corresponding quarter (the "subordination threshold"). If there is not sufficient cash to fund such a distribution on all of the Trust units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on the common units. In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is entitled

to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter (the “incentive threshold”). The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis.

1

Neither the Trust nor the Trustee is responsible for, or has any control over, any costs related to the drilling of the Development Wells or any other operating or capital costs of the Underlying Properties. The Trust's cash receipts with respect to the Royalty Interests in the Underlying Properties are determined after deducting certain post-production expenses and any applicable taxes associated with the Royalty Interests. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and NGL produced. However, the Trust is not responsible for costs of marketing services provided by affiliates of Chesapeake. Cash distributions to unitholders will continue to be reduced by the Trust's general and administrative expenses. Through March 31, 2016, cash distributions to unitholders were increased or decreased by the effect of the Trust's derivative contracts, given that the Trust continued to settle the derivative contracts through February 2016. See Derivative Contracts below.

The Trust will dissolve and begin to liquidate on June 30, 2031, or earlier upon certain events (the "Termination Date"), and will soon thereafter wind up its affairs and terminate. At the Termination Date, (a) 50% of the total Royalty Interests conveyed by Chesapeake (the "Term Royalties") will revert automatically to Chesapeake and (b) 50% of the total Royalty Interests conveyed by Chesapeake (the "Perpetual Royalties") will be retained by the Trust and thereafter sold. The net proceeds of the sale of the Perpetual Royalties, as well as any remaining Trust cash reserves, will be distributed to the unitholders on a pro rata basis. Chesapeake will have a right of first refusal to purchase the Perpetual Royalties retained by the Trust at the Termination Date.

Target Distributions and Subordination and Incentive Thresholds

The Trust is required to make quarterly cash distributions of substantially all of its quarterly cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each quarter through (and including) the quarter ending June 30, 2031. Quarterly distributions to Trust unitholders will generally include royalty income attributable to sales of oil, natural gas and NGL for three months, including the first two months of the quarter just ended and the last month of the quarter prior to that one. The first quarterly distribution was made on December 28, 2011 to record unitholders as of December 15, 2011.

In connection with the initial public offering of the Trust, Chesapeake established quarterly target levels of cash distributions to unitholders for the life of the Trust. These target distributions were used to calculate the subordination and incentive thresholds described in more detail below and do not represent estimates of the actual distributions that may be received by Trust unitholders. Actual cash distributions to the Trust unitholders will fluctuate quarterly based on the quantity of oil, natural gas and NGL sold from the Underlying Properties, the prices received for such sales, the timing of Chesapeake's receipt of payment for such sales, payments or receipts under the Trust's derivative contracts, the Trust's expenses and other factors. While target distributions initially increase as Chesapeake completes its drilling obligation and production increases, target distributions will decline over time as a result of the depletion of the reserves in the Underlying Properties.

Subordination Threshold. In order to provide support for cash distributions on the common units, Chesapeake agreed to subordinate 11,687,500 of the Trust units retained following the initial public offering of common units, which constitute 25% of the outstanding Trust units. The subordinated units are entitled to receive pro rata distributions from the Trust each quarter if and to the extent there is sufficient cash to pay a cash distribution on the common units that is no less than 80% of the target distribution for the corresponding quarter. If there is not sufficient cash to fund such a distribution on all of the common units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on all the common units, including the common units held by Chesapeake.

Incentive Threshold. In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to the Trust unitholders, including Chesapeake, on a pro rata basis.

At the end of the 2017 second quarter, the subordinated units will automatically convert into common units on a one-for-one basis and Chesapeake's right to receive incentive distributions for any subsequent quarter will terminate. With respect to distributions for quarters following the 2017 second quarter, the common units will no longer have the

protection of the subordination threshold, and all Trust unitholders will share on a pro rata basis in the Trust's distributions. The period during which the subordinated units are outstanding is referred to as the subordination period.

The following table sets forth the subordination threshold and the incentive threshold for each calendar quarter through the second quarter of 2017, as established in the Trust Agreement:

Period	Subordination Threshold ⁽¹⁾ (\$ per unit)	Incentive Threshold ⁽¹⁾
2016:		
Fourth Quarter	\$0.41	\$0.62
2017:		
First Quarter	\$0.39	\$0.59
Second Quarter	\$0.37	\$0.56

For each quarter, the subordination threshold equals 80% of the target distribution and the incentive threshold (1) equals 120% of the target distribution. The subordination and incentive thresholds terminate after the distribution is made for the 2017 second quarter.

For the year ended December 31, 2016, the Trust declared and paid the following cash distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit			
		Other Unitholders Than Chesapeake	Chesapeake	per Subordinated Unit ⁽¹⁾	Cash Distribution
June 2016 – August 2016	December 1, 2016	\$0.0857	\$ 0.0857	\$	—
March 2016 – May 2016	August 29, 2016	\$0.0734	\$ 0.0734	\$	—
December 2015 – February 2016	May 31, 2016	\$0.0403	\$ 0.0403	\$	—
September 2015 – November 2015 ⁽²⁾	March 1, 2016	\$0.2195	\$ 0.0369	\$	—

- (1) For the production periods from September 2015 through August 2016, the distribution per common unit was below the applicable subordination threshold, and no distribution was declared for the subordinated units. A distribution of \$0.2195 per common unit was paid on March 1, 2016 to common unitholders of record, other than Chesapeake, as of February 19, 2016. Chesapeake received \$0.0369 per common unit and waived its right to receive the higher distribution on its units with respect to the quarter ended December 31, 2015. The Trust's distributable income for the quarter ended December 31, 2015 was \$0.1567 per common unit. As the distributable income per common unit was below the subordination threshold, no distribution was declared for the subordinated units.

As of March 29, 2017, Chesapeake owned 12,062,500 common units and all 11,687,500 subordinated units, which together represent 50.8% of the outstanding Trust units.

Derivative Contracts

All of the Trust's derivative contracts expired on September 30, 2015. The Trust's derivative contracts were intended to manage its exposure to adverse changes in oil prices. On November 16, 2011, Chesapeake novated derivative contracts to the Trust pursuant to which the Trust became party to derivative contracts covering a portion of its expected production from October 1, 2011 through September 30, 2015. These derivative contracts consisted of fixed-price oil swaps, in which the Trust received a fixed price and paid a floating market price, based on NYMEX settlement prices, to the counterparty for the underlying commodity of the derivative. The derivative contracts were not qualified for hedge accounting treatment, and therefore all mark-to-market fluctuations were recorded to Trust corpus when cash settled. As a party to these contracts, the Trust received payments directly from its counterparty or was required to pay any amounts owed directly to its counterparty. All swaps were net settled based on the difference between the fixed-price payment and the floating-price payment.

Settlement of the Trust's derivative contracts continued through February 2016. See Note 3 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the derivative contracts.

Administrative Services Agreement

On November 16, 2011, the Trust entered into an administrative services agreement with Chesapeake, effective July 1, 2011, pursuant to which Chesapeake provides the Trust with certain accounting, tax preparation, bookkeeping and information services related to the Royalty Interests and the registration rights agreement. In return for the services provided by Chesapeake under the administrative services agreement, the Trust pays Chesapeake an annual fee of \$200,000, which is paid in equal quarterly installments and remains fixed for the life of the Trust. Chesapeake is also entitled to receive reimbursement for its actual out-of-pocket fees, costs and expenses incurred in connection with the provision of any of the services under the agreement.

Additionally, the administrative services agreement established Chesapeake as the Trust's hedge manager, pursuant to which Chesapeake has the authority, on behalf of the Trust, to administer the Trust's derivative contracts. The Trust had no derivative contracts as of December 31, 2016.

The administrative services agreement will terminate upon the earliest to occur of (a) the date the Trust shall have been wound up in accordance with the Trust Agreement, (b) the date that all of the Royalty Interests have been terminated or are no longer held by the Trust, (c) with respect to services to be provided with respect to any Underlying Properties being transferred by Chesapeake, the date that either Chesapeake or the Trustee may designate by delivering 90-days prior written notice, provided that Chesapeake's drilling obligation has been completed and the transferee of such Underlying Properties assumes responsibility to perform the services in place of Chesapeake or (d) a date mutually agreed by Chesapeake and the Trustee.

Description of the Trust

Common Units and Subordinated Units. Each Trust unit is a unit of the beneficial interest in the Trust and is entitled to receive cash distributions from the Trust on a pro rata basis. The Trust has 46,750,000 Trust units issued and outstanding, consisting of 35,062,500 common units and 11,687,500 subordinated units. The common units and subordinated units have identical rights and privileges, except with respect to their voting rights and rights to receive distributions.

The subordinated units will automatically convert into common units on a one-for-one basis at the end of the fourth full calendar quarter following Chesapeake's satisfaction of its drilling obligation to the Trust with respect to the Development Wells. Chesapeake fulfilled its drilling obligation as of June 30, 2016, and the subordinated units will convert to common units at the end of the 2017 second quarter.

Distributions and Income Computations. The Trust is required to make quarterly cash distributions to unitholders from its available funds for such calendar quarter. Royalty Interest payments due to the Trust with respect to any calendar quarter are based on actual sales volumes attributable to the Trust's interests in the Underlying Properties (as measured at Chesapeake's metering systems) for the first two months of the quarter just ended as well as the last month of the immediately preceding quarter and actual revenues received for such volumes. Chesapeake makes the Royalty Interest payments to the Trust within 35 days of the end of each calendar quarter. Taking into account the receipt and disbursement of all such amounts, the Trustee determines for such calendar quarter the amount of funds available for distribution to the Trust unitholders. Available funds are the excess cash, if any, received by the Trust over

the Trust's expenses for that quarter. Available funds are reduced by any cash the Trustee decides to hold as a reserve against future liabilities.

The Trustee distributes cash approximately 60 days (or the next succeeding business day following such day if such day is not a business day) following each calendar quarter to each person who is a Trust unitholder of record on the quarterly record date together with interest expected to be earned on the amount of such quarterly distribution from the date of receipt thereof by the Trustee to the payment date.

Unless otherwise advised by counsel or the IRS, the Trustee treats the income and expenses of the Trust for each quarter as belonging to the Trust unitholders of record on the quarterly record date that occurs in such quarter. Trust unitholders recognize income and expenses for tax purposes in the quarter the Trust receives or pays those amounts, rather than in the quarter the Trust distributes them. Minor variances may occur. For example, the Trustee could establish a reserve in one quarter that would not result in a tax deduction until a later quarter. The Trustee could also make a payment in one quarter that would be amortized for tax purposes over several months.

Transfer of Trust Units. Trust unitholders may transfer their Trust units in accordance with the Trust Agreement. The Trustee does not require either the transferor or transferee to pay a service charge for any transfer of a Trust unit. The Trustee may require payment of any tax or other governmental charge imposed for a transfer. The Trustee may treat the owner of any Trust unit as shown by its records as the owner of the Trust unit. The Trustee will not be considered to know about any claim or demand on a Trust unit by any party except the record owner. A person who acquires a Trust unit after any quarterly record date will not be entitled to the distribution relating to that quarterly record date. Delaware law will govern all matters affecting the title, ownership or transfer of Trust units.

Periodic Reports. The Trustee files all required Trust federal and state income tax and information returns. The Trustee prepares and mails to Trust unitholders a Schedule K-1 and also causes to be prepared and filed reports required to be filed under the Exchange Act, and by the rules of the New York Stock Exchange.

Each Trust unitholder and his representatives have the right, at his own expense and during reasonable business hours upon reasonable prior notice, to examine and inspect the records of the Trust and the Trustee in reference thereto for any purpose reasonably related to the Trust unitholder's interest as a Trust unitholder.

Liability of Trust Unitholders. Under the Delaware Statutory Trust Act, Trust unitholders are entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under the General Corporation Law of the State of Delaware. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation.

Voting Rights of Trust Unitholders. The Trustee or Trust unitholders owning at least 10% of the outstanding Trust units may call meetings of Trust unitholders. The Trust does not intend to hold annual meetings of the Trust unitholders. The Trust is responsible for all costs associated with calling a meeting of Trust unitholders unless such meeting is called by the Trust unitholders, in which case the Trust unitholders are responsible for all costs associated with calling such meeting of Trust unitholders. Meetings must be held in such location as is designated by the Trustee in the notice of such meeting. The Trustee must send written notice of the time and place of the meeting and the matters to be acted upon to all of the Trust unitholders at least 20 days and not more than 60 days before the meeting. Trust unitholders representing a majority of Trust units outstanding must be present or represented to have a quorum. Each Trust unitholder is entitled to one vote for each Trust unit owned. Abstentions and broker non-votes shall not be deemed to be a vote cast.

Unless otherwise required by the Trust Agreement, a matter may be approved or disapproved by the vote of a majority of the Trust units held by the Trust unitholders voting in person or by proxy at a meeting where there is a quorum.

This is true, even if a majority of the total outstanding Trust units did not approve it.

Until such time as Chesapeake and its affiliates own less than 10% of the outstanding Trust units, the affirmative vote of the holders of a majority of common units (excluding common units owned by Chesapeake and its affiliates) and a majority of Trust units voting in person or by proxy at a meeting of such holders at which a quorum is present is required to:

- dissolve the Trust (except in accordance with its terms);
- remove the Trustee or the Delaware Trustee;

amend the Trust Agreement, the royalty conveyances, the administrative services agreement and the development agreement (except with respect to certain matters that do not adversely affect the rights of Trust unitholders in any material respect);

merge, consolidate or convert the Trust with or into another entity; or

approve the sale of all or any material part of the assets of the Trust.

At any time when Chesapeake and its affiliates own less than 10% of the outstanding Trust units, the vote of the holders of a majority of Trust units, including units owned by Chesapeake, voting in person or by proxy at a meeting of such holders at which a quorum is present will be required to take the actions described above.

Certain amendments to the Trust Agreement may be made by the Trustee without approval of the Trust unitholders.

The Trustee must consent before all or any part of the Trust assets can be sold except in connection with the dissolution of the Trust or limited sales directed by Chesapeake in conjunction with its sale of Underlying Properties.

Description of the Trust Agreement. The Trust was created under Delaware law as a separate legal entity to acquire and hold the Royalty Interests for the benefit of the Trust unitholders pursuant to the Trust Agreement among Chesapeake, the Trustee and the Delaware Trustee. The Royalty Interests are passive in nature and neither the Trust nor the Trustee has any control over, or responsibility for, costs relating to the operation of the Underlying Properties. Neither Chesapeake nor other operators of the Underlying Properties have any contractual commitments to the Trust to provide additional funding or to conduct further drilling on or to maintain their ownership interest in any of these properties other than the obligations of Chesapeake to drill the Development Wells.

The Trust Agreement provides that the Trust's business activities are generally limited to owning the Royalty Interests, being a party to the derivative contracts and any activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the Royalty Interests. As a result, the Trust is not generally permitted to acquire other oil, natural gas and NGL properties or royalty interests. The Trust is not able to issue any additional Trust units.

Contractual Rights and Assets of the Trust. Contractual rights of the Trust include the development agreement and administrative services agreement. The assets of the Trust consist of the Royalty Interests and any cash and temporary investments being held for the payment of expenses and liabilities and for distribution to the Trust unitholders.

Duties and Powers of the Trustee. The duties and powers of the Trustee are specified in the Trust Agreement and by the laws of the State of Delaware, except as modified by the Trust Agreement. The Trust Agreement provides that the Trustee shall not have any duties or liabilities, including fiduciary duties, except as expressly set forth in the Trust Agreement and the duties and liabilities of the Trustee as set forth in the Trust Agreement replace any other duties and liabilities, including fiduciary duties, to which the Trustee might otherwise be subject.

The Trustee's principal duties consist of:

collecting cash proceeds attributable to the Royalty Interests;

paying expenses, charges and obligations of the Trust from the Trust's assets;

receiving and making payments under the derivative contracts;

determining whether cash distributions exceed subordination or incentive thresholds, and making cash distributions to the unitholders and Chesapeake (with respect to incentive distributions) in accordance with the Trust Agreement;

causing to be prepared and distributed a Schedule K-1 for each Trust unitholder and to prepare and file tax returns on behalf of the Trust; and

causing to be prepared and filed reports required to be filed under the Exchange Act, and by the rules of any securities exchange or quotation system on which the Trust units are listed or admitted to trading.

Chesapeake will provide administrative and other services to the Trust in fulfillment of certain of the foregoing duties pursuant to the administrative services agreement.

The Trustee may create a cash reserve to pay for future expenses of the Trust. If the Trustee determines that the cash on hand and the cash to be received are insufficient to cover the Trust's expenses, the Trustee may cause the Trust to borrow funds required to pay the expenses. The Trust may borrow the funds from any person, including the Trustee or its affiliates or, as described below, Chesapeake. The terms of such indebtedness, if funds were loaned by the entity serving as Trustee or Delaware Trustee, must be similar to the terms which such entity would grant to a similarly situated, unaffiliated commercial customer, and such entity shall be entitled to enforce its rights with respect to any such indebtedness as if it were not then serving as Trustee or Delaware Trustee. If the Trust borrows funds, the Trust unitholders will not receive distributions until the borrowed funds are repaid (except in certain circumstances, where the Trust borrows funds from Chesapeake).

Each quarter, the Trustee will pay Trust obligations and expenses and distribute to the Trust unitholders the remaining proceeds received from the Royalty Interests. The cash held by the Trustee as a reserve against future liabilities must be invested in:

- interest-bearing obligations of the U.S. government;
- money market funds that invest only in U.S. government securities;
- repurchase agreements secured by interest-bearing obligations of the U.S. government; or
- bank certificates of deposit.

Alternatively, cash held for distribution at the next distribution date may be held in a non-interest bearing account.

The Trustee withheld approximately \$1.0 million from the first distribution to establish an initial cash reserve available for Trust expenses. If the Trustee uses its cash reserve (or any portion thereof) to pay or reimburse Trust liabilities or expenses, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until the cash reserve is replenished. Additional cash reserves may also be established from time to time as determined by the Trustee to pay for future expenses of the Trust. This cash reserve will be part of the Trust estate and will bear interest at the same rate as other cash on hand in the Trust estate. Upon the dissolution of the Trust, after payment of Trust liabilities, the balance of the cash reserve (including accrued interest thereon) will be distributed to Trust unitholders on a pro rata basis.

The Trust may not acquire any asset except the Royalty Interests, the other assets described above under Contractual Rights and Assets of the Trust and cash and temporary cash investments, and it may not engage in any investment activity except investing cash on hand.

The Trust Agreement provides that the Trustee will not make business decisions affecting the assets of the Trust.

However, the Trustee may:

- prosecute or defend, and settle, claims of or against the Trust or its agents;
- retain professionals and other third parties to provide services to the Trust;
- charge for its services as Trustee;
- retain funds to pay for future expenses and deposit them with one or more banks or financial institutions (which may include the Trustee to the extent permitted by law);
- lend funds at commercial rates to the Trust to pay the Trust's expenses; and
- seek reimbursement from the Trust for its out-of-pocket expenses.

In discharging its duty to Trust unitholders, the Trustee may act in its discretion and will be liable to the Trust unitholders only for willful misconduct, bad faith or gross negligence, and certain taxes, fees and other charges based on fees, commissions or compensation received by the Trustee in connection with the transactions contemplated by the Trust Agreement. The Trustee is not liable for any act or omission of its agents or employees unless the Trustee acts with willful misconduct, bad faith or gross negligence in its selection and retention. The Trustee will be indemnified individually or as the Trustee for any liability or cost that it incurs in the administration of the Trust, except in cases of willful misconduct, bad faith or gross negligence. The Trustee has a lien on the assets of the Trust as security for this indemnification and its compensation earned as Trustee. Trust unitholders are not liable to the Trustee for any indemnification. The Trustee is obligated to ensure that all contractual liabilities of the Trust are limited to the assets of the Trust.

The Trust may merge or consolidate with or into, or convert into, one or more limited partnerships, general partnerships, corporations, business trusts, limited liability companies, or associations or unincorporated businesses if such transaction is agreed to by the Trustee and approved by the vote of the holders of a majority of the Trust units and a majority of the common units (excluding common units owned by Chesapeake and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present and such transaction is permitted under the Delaware Statutory Trust Act and any other applicable law. At any time that Chesapeake and its affiliates collectively own less than 10% of the outstanding Trust units, however, the standard for approval will be the vote of a majority of the Trust units, including units owned by Chesapeake voting in person or by proxy at a meeting of such holders at which a quorum is present.

Trustee's Power to Sell Trust Assets. The Trustee may sell Trust assets, including the Royalty Interests, under any of the following circumstances:

- the sale is requested by Chesapeake, following the satisfaction of its drilling obligation, in accordance with the provisions of the Trust Agreement; or
- the sale is approved by the vote of holders representing a majority of the Trust units and a majority of the common units (excluding common units owned by Chesapeake and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that Chesapeake and its affiliates collectively own less than 10% of the outstanding Trust units, the standard for approval will be the vote of a majority of the Trust units, including units owned by Chesapeake voting in person or by proxy at a meeting of such holders at which a quorum is present.

Upon dissolution of the Trust, the Trustee must sell the remaining Royalty Interests. No Trust unitholder approval is required in this event.

The Trustee will distribute the net proceeds from any sale of the Royalty Interests and other assets to the Trust unitholders after payment or reasonable provision for payment of the liabilities of the Trust.

Dispute Resolution. To the fullest extent permitted by law, any dispute, controversy or claim that may arise between Chesapeake and the Trustee relating to the Trust will be submitted to binding arbitration before a panel of three arbitrators.

Trust Fees and Expenses. The Trust has been a party to derivative contracts and the Trust previously has had payment obligations under such arrangements. The derivative contracts expired on September 30, 2015, and the Trust does not currently conduct an active business and the Trustee has little power to incur obligations. As a result, it is expected that the Trust will only incur liabilities for routine administrative expenses, such as legal, accounting, audit, tax advisory, engineering, printing and other administrative and out-of-pocket fees and expenses incurred by or at the direction of the Trustee or the Delaware Trustee, including tax return and Schedule K-1 preparation and mailing costs; independent auditor fees; and registrar and transfer agent fees. The Trust is also responsible for paying costs associated with annual and quarterly reports to unitholders. Moreover, the Trustee's and the Delaware Trustee's compensation, and the fee payable to Chesapeake pursuant to the administrative services agreement, are paid out of the Trust's assets.

Chesapeake's Obligation to Fund Trust Expenses in Certain Circumstances. Chesapeake has agreed that, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will lend funds to the Trust necessary to pay such expenses. Any funds loaned by Chesapeake pursuant to this commitment will be limited to the payment of current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or the payment of other accrued current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money. If Chesapeake lends funds pursuant to this commitment, unless Chesapeake agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arms' length transaction between Chesapeake and an unaffiliated third party. There were no loans outstanding as of December 31, 2016. As of December 31, 2015, a \$175,000 loan was outstanding with Chesapeake, and the loan was repaid in March 2016. Chesapeake agreed to permit the Trust to continue making distributions while the loan was outstanding.

Duration of the Trust; Sale of Royalty Interests. The Trust will dissolve and begin to liquidate on June 30, 2031, or earlier upon certain events, and will soon thereafter wind up its affairs and terminate. At the Termination Date, the Term Royalties will revert automatically to Chesapeake. Following the Termination Date, the Perpetual Royalties will be sold by the Trust and the net proceeds of the sale, as well as any remaining Trust cash reserves, will be distributed to the unitholders pro rata. Chesapeake will have a right of first refusal to purchase the Perpetual Royalties from the Trust following the Termination Date.

The Trust will not dissolve until the Termination Date, unless:

- the Trust sells all of the Royalty Interests;
- cash available for distribution is less than \$1.0 million for any four consecutive quarters;
- the holders of a majority of the Trust units and a majority of the common units (excluding common units owned by Chesapeake and its affiliates) in each case voting in person or by proxy at a meeting of such holders at which a quorum is present vote in favor of dissolution; except that at any time that Chesapeake and its affiliates collectively own less than 10% of the outstanding Trust units, the standard for approval will be a majority of the Trust units, including units owned by Chesapeake voting in person or by proxy at a meeting of such holders at which a quorum is present; or
- the Trust is judicially dissolved.

In the case of any of the foregoing, the Trustee would sell all of the Trust's assets, either by private sale or public auction, and distribute the net proceeds of the sale to the Trust unitholders after payment, or reasonable provision for payment, of all Trust liabilities.

Federal Income Tax Considerations

The Trust's federal income tax reporting position is that it is classified as a partnership for federal and applicable state income tax purposes. This position relies on the opinion of Bracewell & Giuliani L.L.P., former counsel to Chesapeake and the Trust, rendered in connection with the initial public offering of the Trust units, in which counsel opined that at least 90% of the Trust's gross income is qualifying income within the meaning of Section 7704 of the Internal Revenue Code of 1986, as amended. The Trust's federal income tax reporting positions are consistent with the Federal Income Tax Considerations section in the prospectus filed by the Trust with the SEC on November 14, 2011, in connection with the initial public offering of its common units (the "Federal Income Tax Considerations Section in the Prospectus"). However, as discussed in detail below under Item 1A. Risk Factors – Tax Risks Related to the Trust's Common Units, the Trust has not requested a ruling from the Internal Revenue Service ("IRS") regarding its U.S. federal income tax reporting positions and its positions may not be sustained by a court or if contested by the IRS. Additional information regarding the opinion and material tax matters is discussed in the Federal Income Tax Considerations Section in the Prospectus.

Competition and Markets

The oil and natural gas industry is highly competitive. Chesapeake competes with both major integrated and other independent oil and natural gas companies in all aspects of its business to explore, develop and operate its properties and market its production. Some of Chesapeake's competitors may have larger financial and other resources than Chesapeake. Competitive conditions may be affected by future legislation and regulations as the United States develops new energy and climate-related policies. In addition, some of Chesapeake's larger competitors may have a competitive advantage when responding to factors that affect demand for oil and natural gas production, such as changing prices, domestic and foreign political conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of natural gas pipelines and other transportation facilities, and overall economic conditions. Chesapeake also faces indirect competition from alternative energy sources, including wind, solar and electric power. Chesapeake believes that its technological expertise, its exploration, land drilling and production capabilities and the experience of its management generally enable it to compete effectively.

Recent volatility in oil, natural gas and NGL prices have adversely impacted, and price fluctuations of oil, natural gas and NGL will continue to directly impact, Trust distributions, estimates of reserves attributable to the Trust's interest, and estimated and actual future net revenues to the Trust. In view of the many uncertainties that affect the supply and demand for oil, natural gas and NGL, neither the Trust nor Chesapeake can make reliable predictions of future supply

and demand for oil, natural gas and NGL, future oil, natural gas and NGL prices or the effect of future oil, natural gas and NGL prices on the Trust.

Regulation

General

All of Chesapeake's operations are conducted onshore in the United States. The U.S. oil and natural gas industry is regulated at the federal, state and local levels, and some of the laws and regulations that govern its operations carry substantial administrative, civil and criminal penalties for non-compliance. Although Chesapeake has advised the Trustee that Chesapeake believes it is in material compliance with all applicable laws and regulations, and that the cost of compliance with existing requirements will not have a material adverse effect on its financial position, cash flows or results of operations, such laws and regulations could be, and frequently are, amended or reinterpreted. Additionally, currently unforeseen environmental incidents may occur or past non-compliance with environmental laws or regulations may be discovered. Therefore, Chesapeake is unable to predict the future costs or impact of compliance or non-compliance. Additional proposals and proceedings that affect the oil and natural gas industry are regularly considered by Congress, the states, local governments, the courts and federal agencies, such as the U.S. Environmental Protection Agency (EPA), the Federal Energy Regulatory Commission (FERC), the Department of Transportation (DOT), the Department of Interior (DOI) and the U.S. Army Corps of Engineers (USACE). Chesapeake has advised the Trustee that Chesapeake actively monitors regulatory developments applicable to the industry in order to anticipate, design and implement required compliance activities and systems.

Exploration and Production

The laws and regulations applicable to Chesapeake's exploration and production operations include requirements for permits or approvals to drill and to conduct other operations and for provision of financial assurances (such as bonds) covering drilling and well operations. Other activities subject to such laws and regulations include, but are not limited to, the following:

- seismic operations;
- the location of wells;
- construction and operations activities, including in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species or their habitats;
- the method of drilling and completing wells;
- production operations, including the installation of flowlines and gathering systems;
- air emissions and hydraulic fracturing;
- the surface use and restoration of properties upon which oil and natural gas facilities are located, including the construction of well pads, pipelines, impoundments and associated access roads;
- water withdrawal;
- the plugging and abandoning of wells;
- the generation, storage, transportation treatment, recycling or disposal of hazardous waste, or other substances in connection with operations;
- the construction and operation of underground injection wells to dispose of produced water and other liquid oilfield wastes;
- the construction and operation of surface pits to contain drilling muds and other fluids associated with drilling operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Delays in obtaining permits or an inability to obtain new permits or permit renewals could inhibit Chesapeake's ability to execute its drilling and production plans. Failure to comply with applicable regulations or permit requirements could result in revocation of Chesapeake's permits, inability to obtain new permits and the imposition of fines and penalties.

Chesapeake's exploration and production activities are also subject to various conservation regulations. These include the regulation of the size of drilling and spacing units (regarding the density of wells that may be drilled in a particular area) and the unitization or pooling of oil and natural gas properties. In this regard, some states, such as Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas, West Virginia and Pennsylvania, rely on voluntary pooling of lands and leases. In areas where pooling is voluntary, it may be more difficult to form units and therefore, more difficult to fully develop a project if the operator owns or controls less than 100% of the leasehold. In addition, some states' conservation laws establish maximum rates of production from oil and natural gas wells, generally limit the venting or flaring of natural gas and impose certain requirements regarding the ratability of production. The effect of these regulations is to limit the amount of oil and natural gas Chesapeake can produce and to limit the number of wells and the locations at which Chesapeake can drill.

Hydraulic Fracturing

Hydraulic fracturing is typically regulated by state oil and gas regulatory authorities, including specifically the requirement to disclose certain information related to hydraulic fracturing operations. Chesapeake follows applicable legal requirements for groundwater protection in its operations that are subject to supervision by state and federal regulators (including the Bureau of Land Management on federal acreage). Furthermore, Chesapeake's well construction practices require the installation of multiple layers of protective steel casing surrounded by cement that are specifically designed and installed to protect freshwater aquifers by preventing the migration of fracturing fluids into aquifers. Regulatory proposals in some states and local communities have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Federal and state agencies continue to assess the impacts of hydraulic fracturing that could spur further action toward federal and/or state legislation and regulation of hydraulic fracturing activities. In addition, in light of concerns about seismic activity being triggered by the injection of produced waters into underground wells and hydraulic fracturing, certain regulators are also considering additional requirements related to seismic safety for hydraulic fracturing activities.

Further restrictions on hydraulic fracturing could make it prohibitive for Chesapeake to conduct operations, and also reduce the amount of oil, natural gas and NGL that Chesapeake is ultimately able to produce in commercial quantities from the Underlying Properties. For further discussion, see Item 1A. Risk Factors – Federal and state legislative and regulatory initiatives relating to hydraulic fracturing could result in increased costs and additional operating restrictions or delays.

Regulation – Environment, Health and Safety

Chesapeake's operations are subject to stringent and complex federal, state and local laws and regulations relating to the protection of human health and safety, the environment and natural resources. These laws and regulations can restrict or impact its business activities in many ways, such as:

- requiring the installation of pollution-control equipment or otherwise restricting the way Chesapeake can handle or dispose of wastes and other substances associated with operations;
- limiting or prohibiting construction activities in sensitive areas, such as wetlands, coastal regions or areas that contain endangered or threatened species and/or species of special statewide concern or their habitats;
- requiring investigatory and remedial actions to address pollution caused by Chesapeake's operations or attributable to former operations;
- requiring noise, lighting, visual impact, odor and/or dust mitigation, setbacks, landscaping, fencing, and other measures;
- restricting access to certain equipment or areas to a limited set of employees or contractors who have proper certification or permits to conduct work (e.g., confined space entry and process safety maintenance requirements); and
- restricting or even prohibiting water use based upon availability, impacts or other factors.

Failure to comply with these laws and regulations may trigger a variety of administrative, civil and criminal enforcement measures against Chesapeake, including the assessment of monetary penalties, the imposition of remedial or restoration obligations, and the issuance of orders enjoining future operations or imposing additional compliance requirements. Certain environmental statutes impose strict, joint and several liability for costs required to

clean up and restore sites where hazardous substances, hydrocarbons or wastes have been disposed or otherwise released. Moreover, local restrictions, such as state or local moratoria, city ordinances, zoning laws and traffic regulations, may restrict or prohibit the execution of Chesapeake's drilling and production plans. In addition, third parties, such as neighboring landowners, may file claims alleging property damage, nuisance or personal injury arising from Chesapeake's operations or from the release of hazardous substances, hydrocarbons or other waste products into the environment.

The trend in environmental regulation is to place more restrictions and limitations on activities that may affect the environment. Chesapeake monitors developments at the federal, state and local levels to inform their actions pertaining to future regulatory requirements that might be imposed to mitigate the costs of compliance with any such requirements and participates in industry groups that help formulate recommendations for addressing existing or future regulations and that share best practices and lessons learned in relation to pollution prevention and incident investigations.

Below is a discussion of the major environmental, health and safety laws and regulations that relate to Chesapeake's business. Chesapeake has advised the Trustee that Chesapeake believes that it is in material compliance with these laws and regulations. Chesapeake does not believe that compliance with existing environmental, health and safety laws or regulations will have a material adverse effect on its financial condition, results of operations or cash flow. At this point, however, Chesapeake has advised the Trustee that it cannot reasonably predict what applicable laws, regulations or guidance may eventually be adopted with respect to its operations or the ultimate cost to comply with such requirements.

Hazardous Substances and Waste

Federal and state laws, in particular the federal Resource Conservation and Recovery Act (RCRA), regulate hazardous and non-hazardous wastes. In the course of Chesapeake's operations, it generates petroleum hydrocarbon wastes such as drill cuttings, produced water and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are not subject to federal regulations governing hazardous wastes, although they are regulated under other federal and state waste laws. At various times in the past, most recently in December 2016, proposals have been made to amend RCRA or otherwise eliminate the exemption applicable to crude oil and natural gas exploration and production wastes. Repeal or modifications of this exemption by administrative, legislative or judicial process, or through changes in applicable state statutes, would increase the volume of hazardous waste Chesapeake is required to manage and dispose and would cause Chesapeake, as well as its competitors, to incur significantly increased operating expenses which could adversely affect the Royalty Interest payments due to the Trust. These wastes may in the future be designated as hazardous wastes and may thus become subject to more rigorous and costly compliance and disposal requirements. Such additional regulation could have a material adverse effect on the cash distributions to the Trust unitholders.

Federal, state and local laws may also require Chesapeake to remove or remediate wastes or hazardous substances that have been previously disposed or released into the environment. This can include removing or remediating wastes or hazardous substances disposed or released by Chesapeake (or prior owners or operators) in accordance with then current laws, suspending or ceasing operations at contaminated areas, or performing remedial well plugging operations or response actions to reduce the risk of future contamination. Federal laws, including the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), and analogous state laws impose joint and several liability, without regard to fault or legality of the original conduct, on classes of persons who are considered legally responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, persons who disposed or arranged for the disposal of hazardous substances at the site, and any person who accepted hazardous substances for transportation to the site. CERCLA and analogous state laws also authorize the EPA, state environmental agencies and, in some cases, third parties to take action to prevent or respond to threats to human health or the environment and/or seek recovery of the costs of such actions from responsible classes of persons.

The Underground Injection Control (UIC) Program authorized by the Safe Drinking Water Act prohibits any underground injection unless authorized by a permit. Chesapeake recycles and reuses some produced water and also disposes of produced water in Class II UIC wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. Permits for Class II UIC wells may be issued by the EPA or

by a state regulatory agency if the EPA has delegated its UIC Program authority. Because some states have become concerned that the disposal of produced water could under certain circumstances contribute to seismicity, they have adopted or are considering adopting additional regulations governing such disposal.

12

Air Emissions

Chesapeake's operations are subject to the federal Clean Air Act (CAA) and comparable state laws and regulations. Among other things, these laws and regulations regulate emissions of air pollutants from various industrial sources, including Chesapeake's compressor stations and production equipment, and impose various control, monitoring and reporting requirements. Permits and related compliance obligations under the CAA, each state's development and promulgation of regulatory programs to comport with federal requirements, as well as changes to state implementation plans for controlling air emissions in regional non-attainment or near-non-attainment areas may require oil and gas exploration and production operators to incur future capital expenditures in connection with the addition or modification of existing air emission control equipment and strategies.

Discharges into Waters

The federal Water Pollution Control Act, or the Clean Water Act (CWA), and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as U.S. waters. Spill prevention, control and countermeasure regulations require appropriate containment berms and similar structures to help prevent the contamination of regulated waters in the event of a hydrocarbon tank spill, rupture or leak. In addition, the CWA and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities and construction activities.

The Oil Pollution Act of 1990 (OPA) establishes strict liability for owners and operators of facilities that release oil into waters of the United States. The OPA and its associated regulations impose a variety of requirements on responsible parties related to the prevention of oil spills and liability for damages resulting from such spills. A "responsible party" under the OPA includes owners and operators of certain onshore facilities from which a release may affect waters of the United States.

Health and Safety

The Occupational Safety and Health Act (OSHA) and comparable state laws regulate the protection of the health and safety of Chesapeake's employees. The federal Occupational Safety and Health Administration has established workplace safety standards that provide guidelines for maintaining a safe workplace in light of potential hazards, such as employee exposure to hazardous substances. OSHA also requires employee training and maintenance of records, and the OSHA hazard communication standard and EPA community right-to-know regulations under the Emergency Planning and Community Right-to-Know Act of 1986 require Chesapeake to organize and/or disclose information about hazardous materials used or produced in its operations.

Endangered Species

The Endangered Species Act (ESA) prohibits the taking of endangered or threatened species or their habitats. While some of Chesapeake's assets and lease acreage may be located in areas that are designated as habitats for endangered or threatened species, Chesapeake believes that it is in material compliance with the ESA. However, the designation of previously unidentified endangered or threatened species in areas where Chesapeake intends to conduct construction activity or the imposition of seasonal restrictions on construction or operational activities could materially limit or delay its plans.

Global Warming and Climate Change

At the federal level, EPA regulations require Chesapeake to establish and report an inventory of greenhouse gas emissions. Legislative and regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could require Chesapeake to incur additional operating costs and could adversely affect demand for the oil and natural gas that it sells. The EPA recently finalized new standards of performance limiting methane emissions from oil and gas sources. The potential increase in Chesapeake's operating costs could include new or increased costs to (a) obtain permits, (b) operate and maintain its equipment and facilities (through the reduction or elimination of venting and flaring of methane), (c) install new emission controls on its equipment and facilities, (d) acquire allowances authorizing its greenhouse gas emissions, (e) pay taxes related to its greenhouse gas emissions and (f) administer and manage a greenhouse gas emissions program. In addition to these federal actions, various state governments and/or regional agencies may consider enacting new legislation and/or promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as Chesapeake's equipment and operations.

In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement requires countries to review and “represent a progression” in their nationally determined contributions, which set emissions reduction goals, every five years. For further discussion, see Item 1A. Risk Factors - Potential legislative and regulatory actions addressing climate change could significantly impact the oil and gas industry and Chesapeake, causing increased costs and reduced demand for oil and natural gas.

Operating Hazards and Insurance

The oil and natural gas business involves a variety of operating risks, including the risk of fire, explosions, blow-outs, pipe failure, abnormally pressured formations and environmental hazards such as oil spills, natural gas leaks, ruptures or discharges of toxic gases. If any of these should occur, Chesapeake could incur legal defense costs and could suffer substantial losses due to injury or loss of life, severe damage to or destruction of property, natural resources and equipment, pollution or other environmental damage, clean-up responsibilities, regulatory investigation and penalties, and suspension of operations. Chesapeake's horizontal and deep drilling activities involve greater risk of mechanical problems than vertical and shallow drilling operations.

As a passive entity, the Trust does not maintain insurance policies for the Underlying Properties. Chesapeake maintains a control of well policy with a \$50 million single well limit and a \$100 million multiple wells limit that insures against certain sudden and accidental risks associated with drilling, completing and operating its wells. There is no assurance that this insurance will be adequate to cover all losses or exposure to liability. Chesapeake also carries a \$460 million comprehensive general liability umbrella policy and a \$150 million pollution liability policy. Chesapeake provides workers' compensation insurance coverage to employees in all states in which it operates. While Chesapeake has informed us that it believes these policies are customary in the industry, they do not provide complete coverage against all operating risks and policy limits scale to Chesapeake's working interest percentage in certain situations. In addition, Chesapeake's insurance does not cover penalties or fines that may be assessed by a governmental authority. A loss not fully covered by insurance could have a material adverse effect on Chesapeake's financial position, results of operations and cash flows. Chesapeake's insurance coverage may not be sufficient to cover every claim made against Chesapeake or may not be commercially available for purchase in the future.

The Underlying Properties and the Royalty Interests

Overview. The Underlying Properties consist of working interests owned by Chesapeake located in the Colony Granite Wash play in Washita County in western Oklahoma arising from leases and farmout agreements related to properties from which the Royalty Interests were conveyed. The AMI consists of approximately 40,500 gross acres (26,400 net acres). As of December 31, 2016 and 2015, the total reserves estimated to be attributable to the Trust were 6,601 mboe (59% natural gas by volume) and 9,502 mboe (57% natural gas by volume), respectively. These amounts include 6,601 mboe of proved developed reserves and no proved undeveloped reserves as of December 31, 2016 and 8,880 mboe of proved developed reserves and 622 mboe of proved undeveloped reserves as of December 31, 2015. The decrease in estimated total reserves attributable to the Trust of 2,901 mboe is primarily attributable to a decrease in production, substantially lower oil and gas prices, shut-in wells, and decreases in forecasts. See Risk Factors – Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the Trust and the value of the Trust units in Item 1A and Risks and Uncertainties in Note 2 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the decrease in reserves.

The Colony Granite Wash is a subset of the greater granite wash plays of the Anadarko Basin. The Colony Granite Wash is located at the eastern end of a series of Des Moines-age granite wash fields that extend along the southern flank of the Anadarko Basin, approximately 60 miles into the Texas Panhandle. These granite wash fields were generally deposited as deep-water turbidites that result in relatively low risk, laterally extensive reservoirs. The productive members of the Colony Granite Wash are encountered between approximately 11,500 and 13,000 feet and lie stratigraphically between the top of the Des Moines formation (or top of Colony Granite Wash 'A') and the top of the Prue formation (or base of Colony Granite Wash 'C'). The individual productive members within the Colony Granite Wash may reach 200 feet or more in gross interval thickness and the targeted porosity zones within these individual members are generally 20 to 75 feet thick. The Colony Granite Wash is primarily a natural gas and natural gas condensate reservoir based on reserve volumes. However, in the Colony Granite Wash, oil and NGL production currently generate more revenue than natural gas production due to higher relative prices for oil and NGL than for

natural gas. Development costs for horizontal wells drilled and completed in the AMI during the years ended December 31, 2016 and 2015 averaged approximately \$61.90 per boe and \$23.32 per boe, respectively. The increase in average

development costs of \$38.58 per boe is primarily due to new wells coming online with less than expected results as well as greater than expected depletion for existing wells.

Royalty Interests. The Royalty Interests were conveyed from Chesapeake's interest in the Underlying Properties effective as of July 1, 2011. As of December 31, 2016, the Trust on average owns a 47.6% net revenue interest in the Producing Wells and a 28.6% net revenue interest in the completed Development Wells. Chesapeake retains 10% of the proceeds from the sales of oil, natural gas and NGL production attributable to its net revenue interest in the Producing Wells, and 50% of the proceeds from the sales of production attributable to its net revenue interest in the Development Wells.

The Royalty Interests were conveyed to the Trust by Chesapeake by means of conveyance instruments that were recorded in the appropriate real property records in Washita County, Oklahoma. The conveyance instruments obligate Chesapeake to act diligently and as a reasonably prudent oil and gas operator would act under the same or similar circumstances as if it were acting with respect to its own properties, disregarding the existence of the Royalty Interests as burdens affecting such properties. We refer to this standard as the "Reasonably Prudent Operator Standard." The Trustee has no ability to manage or influence the operation of the Underlying Properties.

Oil, Natural Gas and NGL Reserves. Proved reserve quantities attributable to the Royalty Interests are calculated by multiplying the gross reserves for each property attributable to Chesapeake's interest by the net revenue interest assigned to the Trust in each property. The reserves related to the Underlying Properties include all proved reserves expected to be economically produced during the life of the properties. The reserves attributable to the Trust's interests include only the reserves attributable to the Underlying Properties that are expected to be produced within the 20-year period prior to the Termination Date as well as the residual 50% interest in the Royalty Interests that the Trust will own on the Termination Date and subsequently sell.

All of the Trust's estimated oil, natural gas and NGL reserves are located within the U.S. The table below sets forth information as of December 31, 2016 with respect to the estimated proved reserves of the Underlying Properties and Royalty Interests and the associated PV-10. Because the Trust will not bear income tax expense, PV-10 and the standardized measure of estimated future net revenue of the Royalty Interests are the same. PV-10 is not intended to represent the current market value of the estimated oil, natural gas and NGL reserves attributable to the Royalty Interests. The reserve estimates were prepared by Software Integrated Solutions, Division of Schlumberger Technology Corporation, in accordance with the criteria established by the SEC.

	Proved Reserves				PV-10 (\$ in thousands)
	Oil (mdbl)	Natural Gas (mmcf)	NGL (mdbl)	Total (mboe)	
Underlying Properties:					
Developed	1,358	46,888	4,127	13,300	\$ 38,853
Undeveloped	—	—	—	—	—
Total	1,358	46,888	4,127	13,300	\$ 38,853
Royalty Interests:					
Developed ⁽¹⁾	686	23,296	2,033	6,601	\$ 34,485
Undeveloped ⁽¹⁾	—	—	—	—	—
Total	686	23,296	2,033	6,601	\$ 34,485

(1)PV-10 for the Royalty Interests was calculated exclusive of any production or development costs.

The proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil, natural gas and NGL for the period from January 1, 2016 through December 1, 2016, without giving effect to derivative contracts, and were held constant for the life of the properties. The prices used in the reserve reports, as well as Chesapeake's internal reports, yield weighted average prices at the wellhead, which are based on first-day-of-the-month reference prices and adjusted for transportation and regional price differentials. For the Royalty Interests, costs of marketing services provided by Chesapeake's affiliates will not be charged to the Trust. The reference prices and the equivalent weighted average wellhead prices are presented in the table below.

Oil (per bbl)	Natural Gas (per mcf)	NGL (per bbl)
12-month average (SEC pricing)		
Weighted average wellhead prices (\$/barrel)	\$ 0.15	\$ 16.43
Properties)		
Weighted average wellhead prices (\$/barrel)		
Royalty Interests)	\$ 0.15	\$ 16.42

As of December 31, 2016, no Royalty Interests were classified as PUDs, compared to 622 mboe as of December 31, 2015. Presented below is a summary of changes in the proved undeveloped reserves for the Royalty Interests for 2016.

	Total (mboe)
Proved undeveloped reserves, beginning of period	622
Extensions and discoveries	—
Developed	(622)
Revisions of previous estimates	—
Proved undeveloped reserves, end of period	0

As of December 31, 2016, there were no PUDs that had remained undeveloped for five years or more. Chesapeake invested approximately \$11.4 million in the Underlying Properties in 2016 to convert 1,465 (622 net to the Royalty Interests) mboe of PUDs to proved developed reserves. All costs were paid by Chesapeake, as the Trust is not responsible for the cost of development.

The annual net decline rate on current producing properties is projected to be 19% from 2017 to 2018, 16% from 2018 to 2019, 14% from 2019 to 2020 and 12% from 2020 to 2021. As of December 31, 2016, of the total proved reserves, 13,300 mboe and 6,601 mboe attributable to the Underlying Properties and the Royalty Interests, respectively, were classified as proved developed producing reserves.

Chesapeake's ownership interest used for calculating proved reserves and the associated estimated future net revenue assumed maximum participation by other parties to Chesapeake's farmout and participation agreements. SEC pricing used for calculating the estimated future net revenues attributable to proved reserves does not reflect actual market prices for oil, natural gas and NGL production sold subsequent to December 31, 2016.

The Trust's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2016, 2015 and 2014, respectively, along with the changes in quantities and standardized measure of such reserves for the three years ended December 31, 2016, 2015 and 2014, respectively, are shown in Supplemental Disclosures About Oil, Natural Gas and NGL Producing Activities included in Item 8 of Part II. No estimates of proved reserves comparable to those included herein have been included in reports to any federal agency other than the SEC.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represent only estimates. Reserve engineering is a subjective process of estimating underground accumulations of oil and natural gas that cannot be measured, and the accuracy of any reserve estimate is a function of the quality of available data and of engineering and geological interpretation and judgment. As a result, estimates made by different engineers often vary. In addition, results of drilling, testing and production subsequent to the date of an estimate may

justify revisions to such estimates, and such revisions may be material. Accordingly, reserve estimates are often different from the actual quantities of oil, natural gas and NGL that are ultimately recovered. Furthermore, the estimated future

net revenue from proved reserves and the associated present value are based upon certain assumptions, including prices, future production levels and costs that may not prove correct. Future prices and costs may be materially higher or lower than the prices and costs as of the date of any estimate.

Development Wells. Pursuant to the development agreement with the Trust, Chesapeake was obligated to drill, cause to be drilled or participate as a non-operator in the drilling of 118 Development Wells by June 30, 2016. Chesapeake had fulfilled its drilling obligation under the development agreement as of June 30, 2016. Chesapeake has retained an interest in each of the Producing Wells and Development Wells and currently operates approximately 96% of the Producing Wells and completed Development Wells. Prior to fulfilling its commitment to drill the Development Wells, Chesapeake was not allowed to drill or complete, or permit any other person within its control to drill or complete: (a) any well in the Colony Granite Wash formation or lease acreage included within the AMI for its own account; or (b) any well that would have had a perforated segment within 600 feet of any perforated interval of any Development Well or Producing Well. Chesapeake's average net revenue interest in the oil and gas properties underlying the Development Royalty Interest is approximately 63%. The Development Royalty Interest entitles the Trust to receive 50% of the proceeds attributable to Chesapeake's net revenue interest in future production of oil, natural gas and NGL from the Development Wells.

The Trust was not responsible for any costs related to the drilling of the Development Wells and is not responsible for any other operating or capital costs of the Underlying Properties, and Chesapeake was not permitted to drill or complete any well in the Colony Granite Wash formation on lease acreage included within the AMI for its own account until it had satisfied its drilling obligation to the Trust. For the life of the Trust, Chesapeake will not be permitted to drill or complete any well that will have a perforated segment within 600 feet of any perforated interval of any Development Well or Producing Well.

Chesapeake granted to the Trust a lien on its interest in the AMI (except the Producing Wells and any other wells that were already producing as of July 1, 2011 and are not subject to the Royalty Interests) in order to secure the estimated amount of the drilling costs for the Trust's interests in the Development Wells (the "Drilling Support Lien"). The amount obtained by the Trust pursuant to the Drilling Support Lien initially could not exceed \$262.7 million. As Chesapeake fulfilled its drilling obligation over time, Development Wells that were completed or that were perforated for completion and then plugged and abandoned were released from the Drilling Support Lien and the total dollar amount that was recoverable by the Trust for Chesapeake's failure to fulfill its drilling obligation was proportionately reduced. The Trust did not obtain any amounts from Chesapeake under the Drilling Support Lien during the period in which Chesapeake was drilling the Development Wells, and the Drilling Support Lien has been reduced to zero. Following the satisfaction of its drilling obligation to the Trust, Chesapeake may, without the consent or approval of the Trust unitholders, sell all or any part of Chesapeake's retained interest in the Underlying Properties. In any such sale by Chesapeake, the Underlying Properties must be sold subject to and burdened by the Royalty Interests, except that Chesapeake may require the Trust to release the Royalty Interests on such Underlying Properties with an aggregate value of up to \$5.0 million during any 12-month period. In such event, the Trust must receive an amount equal to the fair value to the Trust of any royalty interests it sells.

Drilling Activity. The following table sets forth information with respect to the wells Chesapeake drilled or participated in during the periods indicated that were located in the AMI. The information presented is not necessarily indicative of future performance, and should not be interpreted to present any correlation between the number of productive wells drilled and quantities or economic value of reserves found. Gross wells are the total number of producing wells in which Chesapeake has a working interest and net wells are the sum of Chesapeake's fractional working interest owned in such gross wells.

	2016		2015		2014	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Development productive	9	3	6	1	15	4
Exploratory productive	—	—	—	—	2	1
Dry	—	—	—	—	—	—
Total	9	3	6	1	17	5

Developed and Undeveloped Acreage. The following table sets forth information regarding developed and undeveloped acreage held by Chesapeake within the AMI as of December 31, 2016. All of the leases associated with the Underlying Properties are held by production and not subject to expiration so long as production continues in paying quantities.

	Developed		Undeveloped	
	Acreage ⁽¹⁾		Acreage	
	Gross	Net	Gross	Net
Acreage Held by Chesapeake within the AMI	40,236	26,195	—	—

Gross and net developed acres are acres spaced or assignable to productive wells. The drilling unit for each Colony (1) Granite Wash horizontal well comprises 640 acres. As such, developed acreage may include up to 640 acres assigned to each Colony Granite Wash horizontal well.

Marketing and Post-Production Services. Pursuant to the terms of the conveyances creating the Royalty Interests, Chesapeake has the responsibility to market, or cause to be marketed, the oil, natural gas and NGL production related to the Underlying Properties. While marketing costs of non-affiliates of Chesapeake are deducted from the proceeds upon which the royalty payments are calculated, the Trust is not responsible for costs of marketing services provided by Chesapeake or any of its affiliates. Chesapeake Energy Marketing, L.L.C. ("CEMLLC"), a wholly owned subsidiary of Chesapeake, markets the majority of Chesapeake's operated production. CEMLLC enters into oil, natural gas and NGL sales arrangements with large aggregators of supply, and these arrangements may be on a month-to-month basis or for a term of up to one year or longer. The oil, natural gas and NGL are sold at market prices and subsequently any applicable post-production expenses will be deducted. CEMLLC sells production from the Underlying Properties to a diverse group of aggregators, the identity of which changes from time to time. As a result, the proceeds to the Trust from the sales of oil, natural gas and NGL production from the Underlying Properties is determined based on the same price (net of post-production costs and production taxes) that Chesapeake receives from third parties for oil, natural gas and NGL production attributable to Chesapeake's remaining interest in the Underlying Properties.

Post-production expenses are deducted from proceeds paid to the Trust. Williams Partners, L.P. ("WMB"), provides gathering, treating, compression and other post-production services and Enable Midstream Partners, LP ("Enable") (formerly Enogex LLC) provides processing, transportation and other post-production services. The proceeds paid to the Trust are reduced by deductions for these post-production expenses.

Post-production expenses may be deducted by the ultimate purchaser of the oil, natural gas and NGL prior to payment being made to Chesapeake or CEMLLC for such production. At other times, Chesapeake or CEMLLC makes payments directly to the applicable provider of such post-production services. In either instance, the Trust's cash available for distribution is reduced by the expenses incurred by Chesapeake or CEMLLC for such post-production services. If the post-production expenses are expressed as a percentage of the gross production from a well, then the volume of production from that well actually available for sale is less the applicable percentage charged, and as a result the reserves associated with that well that are attributable to the Royalty Interest are reduced accordingly.

The post-production expenses are negotiated based on market conditions at the time or pursuant to a state or federal regulatory proceeding. Chesapeake is permitted to deduct from the proceeds available to the Trust other post-production expenses necessary to enhance the value of the oil, natural gas and NGL from the Underlying Properties and to transport such production to market.

Natural gas and NGL produced from the Underlying Properties are gathered by gathering pipelines owned by WMB under a contract that expires in approximately 13 years. NGL and natural gas are processed at facilities owned by Enable under a contract that expires in 2017 and then sold to a number of primary purchasers in the area. Oil produced from the Underlying Properties is gathered by gathering pipelines and equipment owned by WMB or transported by trucks owned by third parties and sold to Enable. In the event of a loss of its contracts with WMB or Enable, Chesapeake believes that the availability of other customers and service providers in the area is sufficient to accommodate such loss.

Any new oil, natural gas and NGL supply arrangements or those entered into for providing post-production services will be utilized in determining the proceeds for the Underlying Properties.

Discussion and Analysis of Results from the Underlying Properties

Historical Results. The Underlying Properties consist of the working interests owned by Chesapeake in the Colony Granite Wash in Washita County in western Oklahoma arising under leases and farmout agreements related to properties from which the PDP Royalty Interest and the Development Royalty Interest were conveyed.

The following table provides revenues and direct operating expenses for the years ended December 31, 2016, 2015 and 2014, as derived from the Underlying Properties' statements of revenues and direct operating expenses.

	Years Ended December 31,		
	2016	2015	2014
	(\$ in thousands)		
Oil, natural gas and NGL revenues ⁽¹⁾	\$22,582	\$40,665	\$165,418
Direct operating expenses:			
Production expenses excluding taxes	6,759	10,277	13,454
Production taxes	702	31	2,946
Ad valorem taxes	6	2	84
Total direct operating expenses	7,467	10,310	16,484
Revenues in excess of direct operating expenses	\$15,115	\$30,355	\$148,934

(1) Oil, natural gas and NGL revenues are net of post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses.

The following table sets forth the production, average sales prices, and average cost per boe for production expenses and production taxes for the Underlying Properties for the years ended December 31, 2016, 2015 and 2014.

	Years Ended December 31,		
	2016	2015	2014
Production:			
Oil (mbbls)	315	478	791
Natural gas (mmcf)	7,423	11,130	17,379
NGL (mbbls)	714	887	1,776
Total production (mboe)	2,266	3,220	5,464
Average sales prices: ⁽¹⁾			
Oil (per bbl)	\$40.38	\$43.58	\$89.50
Natural gas (per mcf)	\$2.66	\$0.72	\$2.53
NGL (per bbl)	\$16.98	\$13.30	\$28.48
Average (per boe)	\$19.67	\$12.63	\$30.27
Direct operating expenses:			
Production expenses (per boe) ⁽²⁾	\$2.99	\$3.19	\$2.48
Production taxes (per boe) ⁽³⁾	\$0.31	\$0.01	\$0.54

(1) Average sales prices are net of post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses.

(2) Production expenses include lease operating costs and ad valorem taxes.

(3) Production taxes are generally based upon (a) volume produced and (b) prices received for production.

Oil, Natural Gas and NGL Revenues. For the year ended December 31, 2016, oil, natural gas and NGL revenues were \$22.6 million compared to \$40.7 million and \$165.4 million for the years ended 2015 and 2014, respectively. The \$18.1 million decrease in revenues from 2015 to 2016 was primarily due to a decrease in production and a decrease in the average sales price of oil. The decrease in the price received per boe in 2016 compared to 2015 resulted in a \$6.0 million decrease in oil, natural gas and NGL revenues. Average oil prices decreased \$3.20 per bbl, from \$43.58 per bbl for the year ended December 31, 2015 to \$40.38 per bbl for the year ended December 31, 2016. Average natural gas prices increased \$1.94 per mcf, from \$0.72 per mcf for the year ended December 31, 2015 to \$2.66 per mcf for the year ended December 31, 2016. NGL prices increased \$3.68 per bbl, from \$13.30 per bbl for the year ended December 31, 2015 to \$16.98 per bbl for the year ended December 31, 2016. Decreased sales volumes resulted in a \$12.1 million decrease in oil, natural gas and NGL revenues, for a net decrease in oil, natural gas and NGL revenues of \$18.1 million from 2015 to 2016.

The \$124.7 million decrease in revenues from 2014 to 2015 was primarily due to a decrease in production of 2,244 mboe and a decrease in the average sales price of oil, natural gas and NGL. Decreased sales volumes resulted in a \$67.9 million decrease in oil, natural gas and NGL revenues. The decrease in the sales price received per boe in 2015 compared to the 2014 resulted in a \$56.8 million decrease in oil, natural gas and NGL revenues, for a net decrease in oil, natural gas and NGL revenues of \$124.7 million from 2014 to 2015.

Production Expenses. For the year ended December 31, 2016, production expenses, excluding ad valorem taxes, were \$6.8 million compared to \$10.3 million and \$13.5 million for the years ended 2015 and 2014, respectively. On a unit-of-production basis, production expenses, including ad valorem taxes, were \$2.99 per boe in 2016 compared to \$3.19 and \$2.48 per boe in 2015 and 2014, respectively.

Production Taxes. For the year ended December 31, 2016, production taxes were \$0.7 million, compared to a nominal amount and \$2.9 million for the years ended 2015 and 2014, respectively. On a unit-of-production basis, production taxes were \$0.31 per boe in 2016 compared to \$0.01 per boe in 2015 and \$0.54 per boe in 2014. Severance tax exemptions related to economically at risk wells for prior periods were realized in 2015, causing production taxes per boe in 2015 to be significantly lower than production taxes per boe in 2016.

The Reserve Report for the Underlying Properties and the Royalty Interests

The oil, natural gas and NGL reserves in this Annual Report were estimated by Software Integrated Solutions, Division of Schlumberger Technology Corporation ("Software Integrated Solutions"). The process to review and estimate the reserves begins with Chesapeake's Corporate Reserves Department collecting and verifying all pertinent data, including but not limited to well test data, production data, historical pricing, cost information, property ownership interests, reservoir data, and geosciences data. This data is reviewed by various levels of Chesapeake management for accuracy before consultation with Software Integrated Solutions. Software Integrated Solutions was consulted with regularity during the reserve estimation process to review properties, assumptions, and any new data available. Internal reserve estimates and methodologies are compared to Software Integrated Solutions' estimates and methodologies to test the reserve estimates and conclusions before the reserve estimates are included in this Annual Report. Additionally, Chesapeake's senior management reviews and approves the reserve report contained herein.

Internal Controls. Chesapeake's Director - Corporate Reserves is the technical person primarily responsible for overseeing the preparation of the Trust's reserve estimates. His qualifications include the following:

- 26 years of practical experience working for major oil companies, including 18 years in reservoir engineering responsible for estimation and evaluation of reserves;

- Bachelor of Science degree in Petroleum Engineering;

- registered professional engineer in the state of Texas; and

- member in good standing of the Society of Petroleum Engineers.

Chesapeake ensures that the key members of Chesapeake's Corporate Reserves Department have appropriate technical qualifications to oversee the preparation of reserves estimates. Each of Chesapeake's Corporate Reserves Advisors has more than 30 years' experience in reserve estimation as a reservoir engineer. Each of its engineering technicians has a minimum of a four-year degree in mathematics, economics, finance or other technical/business/science field.

Chesapeake also maintains a continuous education program for its engineers and technicians on new technologies and industry advancements and offer refresher training on basic skill sets.

Chesapeake maintains internal controls such as the following to ensure the reliability of reserves estimations: Chesapeake follows comprehensive SEC-compliant internal policies to estimate and report proved reserves. Reserves estimates are made by experienced reservoir engineers or under their direct supervision. All material changes are reviewed and approved by Chesapeake's Corporate Reserve Advisors.

Chesapeake's Corporate Reserves Department reviews all of Chesapeake's and the Trust's proved reserves at the close of each quarter.

Each quarter, Chesapeake's Corporate Reserves Department managers, the Director - Corporate Reserves, the Vice Presidents of its business units, the Director of Corporate and Strategic Planning and the Executive Vice President - Exploration and Production review all significant reserves changes and all new proved undeveloped reserves additions.

Chesapeake's Corporate Reserves Department reports independently of Chesapeake's operating divisions.

Technologies. The reserve report was prepared using decline curve analysis to determine the reserves of individual Producing Wells. After estimating the reserves of each proved developed well, it was determined that a reasonable level of certainty exists with respect to the reserves that can be expected from close offset undeveloped wells in the field. The continuity of the play across the AMI area was established by reviewing electronic well logs from wells, geologically mapping the analogous reservoir and reviewing extensive production data from horizontal wells within the larger Colony Granite Wash area.

Software Integrated Solutions. Chesapeake engaged Software Integrated Solutions, a third-party engineering firm, to prepare all of the Trust's estimated proved reserves as of December 31, 2016. A copy of the report issued by the engineering firm is filed with this report as Exhibit 99.1. The qualifications of the technical person at the firm primarily responsible for overseeing the preparation of the Trust's reserve estimates are set forth below.

over 30 years of practical experience in the estimation and evaluation of reserves;

registered professional geologist licensed in the Commonwealth of Pennsylvania;

member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers; and

Bachelor of Science degree in Geological Sciences.

Miscellaneous

The Trustee may consult with counsel (which may include counsel to Chesapeake), accountants, tax advisors, geologists and engineers and other parties the Trustee believes to be qualified as experts on the matters for which advice is sought. The Trustee is protected for any action it takes in good faith reliance upon the opinion of the expert. The Delaware Trustee and the Trustee may resign at any time or be removed with or without cause at any time by the vote of a majority of the outstanding Trust units (excluding common units owned by Chesapeake and its affiliates) voting in person or by proxy at a meeting of such holders at which a quorum is present; except that at any time that Chesapeake and its affiliates collectively own less than 10% of the outstanding Trust units, the standard for approval will be the vote of a majority of the Trust units, including units owned by Chesapeake, voting in person or by proxy at a meeting of such holders at which a quorum is present. Abstentions and broker non-votes shall not be deemed to be votes cast. Any successor must be a bank or trust company meeting certain requirements, including having combined capital, surplus and undivided profits of at least \$20 million, in the case of the Delaware Trustee, and \$100 million, in the case of the Trustee.

ITEM 1A. Risk Factors

Risks Related to the Units

Producing oil, natural gas and NGL on the Underlying Properties is a high-risk activity with many uncertainties. Any delays or reductions in production could decrease cash available for distribution to unitholders.

Producing oil, natural gas and NGL can be unprofitable if productive wells do not produce sufficient revenues to return a profit. Chesapeake's and third-party operators' decisions to develop or otherwise exploit certain areas within the AMI depended in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. Production operations on the Underlying Properties may be curtailed, delayed or canceled as a result of various factors, including the following:

- unusual or unexpected geological formations and miscalculations or irregularities in formations;
- equipment malfunctions, failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;
- pipe or cement failures and casing collapses;
- pressures, fires, blowouts and explosions;
- lost or damaged service tools;
- uncontrollable flows of oil, natural gas and NGL water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil, natural gas and NGL leaks, pipeline ruptures and discharges of toxic gases or fluids;
- adverse weather conditions, such as extreme cold, fires caused by extreme heat or lack of rain and severe storms or tornadoes;
- reductions in oil, natural gas and NGL prices; and
- title problems affecting the Underlying Properties.

If the Producing Wells or Development Wells have lower than anticipated production due to one of the factors above or for any other reason, cash distributions to unitholders may be reduced.

Oil, natural gas and NGL prices fluctuate widely, and depressed prices for an extended period of time are likely to have a material adverse effect on proceeds to the Trust, Chesapeake's economic incentive to drill and cash distributions to unitholders.

The Trust's reserves and quarterly cash distributions depend primarily upon the prices realized from the sales of oil, natural gas and NGL. Chesapeake requires substantial expenditures to replace reserves, sustain production and fund its business plans. Low oil, natural gas and NGL prices can negatively affect the amount of cash available for capital expenditures and debt repayment and the ability to borrow money or raise additional capital and, as a result, could have a material adverse effect on Chesapeake's financial condition, results of operations, cash flows and reserves and the Trust's reserves and quarterly cash distributions. Historically, the markets for oil, natural gas and NGL have been volatile and they are likely to continue to be volatile. Wide fluctuations in oil, natural gas and NGL prices may result from relatively minor changes in the supply of or demand for oil, natural gas and NGL, market uncertainty and other factors that are beyond the control of the Trust and Chesapeake, including:

- domestic and worldwide supplies of oil, natural gas and NGL, including U.S. inventories of oil and natural gas reserves;
- weather conditions;
- changes in the level of consumer and industrial demand;
- the price and availability of alternative fuels;

- the effectiveness of worldwide conservation measures;
- the availability, proximity and capacity of pipelines, other transportation facilities and processing facilities;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others;
- U.S. exports of oil and/or liquefied natural gas;
- the price and level of foreign imports;
- the nature and extent of domestic and foreign governmental regulations and taxes;
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls;
- political instability or armed conflict in oil and natural gas producing regions;
- acts of terrorism; and
- domestic and global economic conditions.

These factors and the volatility of the energy markets make it extremely difficult to predict future oil, natural gas and NGL price movements with any certainty. Oil and natural gas prices remained low throughout 2016 and continuing into the first quarter of 2017.

Lower oil, natural gas and NGL prices have reduced, and could continue to reduce, proceeds to which the Trust is entitled and may ultimately reduce the amount of oil, natural gas and NGL that is economic to produce from the Underlying Properties. As a result, Chesapeake or any third-party operator of any of the Underlying Properties could determine during periods of low oil, natural gas and NGL prices to shut in or curtail production from wells on the Underlying Properties. In addition, the operator of the Underlying Properties could determine during periods of low oil, natural gas and NGL prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, Chesapeake or any third-party operator may abandon any well or property if it reasonably believes that the well or property can no longer produce oil, natural gas and NGL in commercially economic quantities. This could result in termination of the portion of the Royalty Interests relating to the abandoned well or property, and Chesapeake would have no obligation to drill a replacement well. The volatility of oil, natural gas and NGL prices also reduces the accuracy of target distributions used to calculate the subordination and incentive thresholds.

Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the Trust and the value of the Trust units.

The value of the Trust units and the amount of future cash distributions to the Trust unitholders will depend upon, among other things, the accuracy of the future production estimated to be attributable to the Royalty Interests. The future production estimates are based on estimates of reserve quantities for the Underlying Properties. Estimates of proved reserves and estimated future net revenues from proved reserves are based upon various assumptions, including assumptions required by the SEC relating to oil, natural gas and NGL prices, drilling and operating expenses, capital expenditures, taxes and availability of funds. The process of estimating oil, natural gas and NGL reserves is complex and involves significant decisions and assumptions associated with geological, geophysical, engineering and economic data for each well. Therefore, these estimates are subject to further revisions.

Actual future production attributable to the Royalty Interests, oil, natural gas and NGL prices, revenues, taxes, development expenditures, operating expenses and quantities of recoverable oil, natural gas and NGL reserves most likely will vary from these estimates. Such variations may be significant and could materially affect the estimated quantities and present value of proved reserves. In addition, we may adjust estimates of proved reserves to reflect production history, results of exploration and development drilling, prevailing oil and natural gas prices and other factors, many of which are beyond our control.

As of December 31, 2016, none of the Trust's estimated proved reserves (by volume) were undeveloped.

The present values included in this report do not represent the current market value of the Trust's estimated reserves. In accordance with SEC requirements, the estimates of our present values are based on prices and costs

as of the date of the estimates. The price on the date of estimate is calculated as the average oil and natural gas price during the 12 months ending in the current reporting period, determined as the unweighted arithmetic average of prices on the first day of each month within the 12-month period. The December 31, 2016 present value is based on \$42.75 per bbl of oil and \$2.49 per mcf of natural gas before basis differential adjustments. Actual future prices and costs may be materially higher or lower than the prices and costs as of the date of an estimate.

The timing of both the production and the expenses from the development and production of oil and natural gas properties will affect both the timing of actual future net cash flows from our proved reserves and their present value. Any changes in consumption or in governmental regulations will also affect the actual future net cash flows from our production. In addition, the 10% discount factor which is required by the SEC to be used in calculating discounted future net cash flows for reporting purposes is not necessarily the most appropriate discount factor. Interest rates in effect from time to time and the risks associated with our business or the oil and gas industry in general will affect the appropriateness of the 10% discount factor.

Reserve estimates for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in estimates of proved reserves, future production rates and the timing of development expenditures. Most of the Producing Wells have been operational for a relatively short period of time and estimated total reserves vary substantially from well to well and are not directly correlated to perforated lateral length or completion technique. There can be no assurance that the data used in preparing these estimates can accurately predict future production. The lack of operational history for horizontal wells in the Colony Granite Wash may also contribute to the inaccuracy of estimates of proved reserves. During 2016, the Trust recorded downward reserve revisions primarily due to higher-than-expected pressure depletion within certain areas of the AMI. During 2015, the Trust recorded significant downward reserve revisions primarily due to a decrease in commodity prices and the removal of PUDs that were not part of Chesapeake's drilling plan within the AMI. During 2014, the Trust recorded significant downward reserve revisions primarily due to the then current results being below expectations, primarily as a result of higher-than-expected pressure depletion within certain areas of the AMI and the removal of PUDs that were not part of Chesapeake's five-year development plan within the AMI. Future negative well performance or lower expected ultimate recovery could lead to further downward adjustments to our reserve estimates. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates would have a material adverse effect on the financial condition, results of operations and cash flows of the Trust and would reduce cash distributions to Trust unitholders.

Chesapeake's ability to satisfy its obligations to the Trust depends on its financial position, and in the event of Chesapeake's bankruptcy, it may be expensive and time-consuming for the Trust to exercise its remedies and the Trust may be treated as an unsecured creditor of Chesapeake.

Pursuant to the terms of the development agreement, Chesapeake was obligated to drill and complete, or participate as a non-operator in the drilling and completion of, the Development Wells at its own expense. As of June 30, 2016, Chesapeake had fulfilled its drilling and completion obligation under the development agreement. The conveyances provide that Chesapeake is obligated to market, or cause to be marketed, the oil, natural gas and NGL production related to the Underlying Properties. Due to the Trust's reliance on Chesapeake to fulfill these obligations, the value of the Royalty Interests and its ultimate cash available for distribution is highly dependent on Chesapeake's performance. Chesapeake's ability to perform its obligations will depend on its future financial condition, economic performance and access to capital, which in turn will depend upon the supply and demand for oil, natural gas and NGL, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control. The proceeds of the Royalty Interests may be commingled, for a period of time, with proceeds of Chesapeake's retained interest in the Underlying Properties, and Chesapeake will not be required to maintain a segregated account for proceeds payable to the Trust. In the event of a collection proceeding, it is possible that the Trust may not have adequate facts to trace its entitlement to funds in the commingled pool of funds and that other persons may, in asserting claims against Chesapeake's retained interest, be able to assert claims to the proceeds that should be delivered to the Trust. In addition, during any bankruptcy of Chesapeake, it is possible that payments of the royalties may be delayed or deferred. During the pendency of any Chesapeake bankruptcy proceedings, the ability to collect cash payments being held in Chesapeake's accounts that are attributable to production from the Trust properties, and

even its ability to demand any of these remedies, may be stayed or prohibited by the bankruptcy proceeding.

In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed the Royalty Interests to the Trust, the Trust could lose the value of all of the Royalty Interests if a bankruptcy court were to hold that the Royalty Interests constitute an asset of the bankruptcy estate. Chesapeake and the Trust believe that the Royalty Interests would not be included in any such bankruptcy estate because the recordation of the conveyance of the Royalty Interests in the appropriate real property records in Oklahoma will constitute the conveyance of fully vested real property interests under Oklahoma law or interests in hydrocarbons in place or to be produced under Oklahoma law. Oklahoma law, however, is not entirely clear as to whether an overriding royalty interest is a real property interest. While the Oklahoma Supreme Court has held that royalty interests are real property interests, such cases did not expressly overturn prior Oklahoma Supreme Court cases holding that an overriding royalty interest was not necessarily a real property interest. In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed the Royalty Interests to the Trust, if a bankruptcy court held that (a) the Royalty Interests did not constitute fully vested real property interests or interests in hydrocarbons in place or to be produced or (b) the Royalty Interests were not otherwise eligible to be excluded from the bankruptcy estate under federal bankruptcy law, the Royalty Interests may be treated as unsecured claims of the Trust against Chesapeake. If that were the case, creditors of Chesapeake would be able to claim the Royalty Interests as an asset of the bankruptcy estate to be sold to satisfy obligations to them and the Trust could lose the entire value of the Royalty Interests to senior creditors of Chesapeake.

Estimates of the target distributions to unitholders used to calculate the subordination thresholds and incentive thresholds were based on assumptions that are inherently subjective and are subject to significant business, economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual cash distributions to differ materially from those estimated.

The estimates of target distributions used to calculate the subordination thresholds and incentive thresholds were established by Chesapeake, and Chesapeake did not seek or receive an opinion or report on such estimates from any independent accountants, financial advisers or third-party reserve engineers. Such estimates were based on assumptions about drilling, production, oil, natural gas and NGL prices, hedging activities, capital expenditures, expenses, tax rates and production tax credits under state law and other matters that are inherently uncertain and are subject to significant business, economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated. For example, these estimates assumed that oil, natural gas and NGL production would be sold at prices consistent with spot and settled NYMEX pricing for July through November 2011, monthly NYMEX forward pricing as of October 28, 2011 for the remainder of the period ending June 30, 2014 and assumed price increases after June 30, 2014 of 2.5% annually, capped at \$120.00 per bbl of oil (which cap would be reached in 2025) and \$7.00 per mmbtu of natural gas (which cap would be reached in 2028); however, actual sales prices have not increased at this rate and have declined, and may continue to decline, as they have since the end of 2014. Additionally, these estimates assumed that the Underlying Properties would achieve production volumes set forth in the reserve reports included in the Prospectus; however, actual production volumes have been, and are expected to continue to be, significantly lower. Further, production operations may be curtailed, delayed or terminated as a result of a variety of risks and uncertainties.

Furthermore, neither the target distribution nor the subordination threshold for each quarter during the subordination period necessarily represents the actual cash distributions Trust unitholders will receive, as evidenced by the distributions to common unitholders since the 2013 third quarter distribution that have all been below the subordination threshold. To the extent actual production volumes or sales prices of oil, natural gas and NGL continue to be lower than the assumptions used to generate the target distributions, the actual distributions Trust unitholders receive are expected to be lower than the target distribution and the subordination threshold for the applicable quarter. A cash distribution to Trust unitholders below the target distribution amount or the subordination threshold may materially adversely affect the market price of the Trust units.

The subordination of certain Trust units held by Chesapeake does not assure that Trust unitholders will in fact receive any specified return on investment in the Trust.

Although Chesapeake will not be entitled to receive any distribution on its subordinated units unless there is enough cash for all of the common units to receive a distribution equal to the subordination threshold for such quarter, the

subordinated units constitute only a 25% interest in the Trust, and this feature does not guarantee that common units will receive a distribution equal to the subordination threshold, or any distribution at all. Depending on the prices at which Chesapeake is able to sell volumes attributable to the Trust, the common units may continue to receive a distribution that is below the subordination threshold. Additionally, the subordination period will terminate and the

subordinated units will convert into common units at the end of the 2017 second quarter. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share on a pro rata basis in the Trust's distributions. As of June 30, 2016, Chesapeake had fulfilled its drilling obligation under the development agreement.

Quarterly cash distributions are made by the Trust based on the proceeds received by the Trust pursuant to the Royalty Interests for the preceding calendar quarter. If a quarterly cash distribution is lower than the target distribution amount or subordination threshold for any quarter, the common units will not be entitled to receive any additional distributions nor will the units be entitled to arrearages in any future quarter.

Chesapeake may not serve as the operator of as many of the Developmental Wells as it expects and Chesapeake will rely upon unaffiliated third parties, who may be less qualified, to operate the Development Wells.

Pursuant to the development agreement between Chesapeake and the Trust, Chesapeake was obligated to, and did, drill and complete the equivalent of 118 Development Wells in the AMI as of June 30, 2016. Chesapeake owns a majority working interest in all of the locations on which it drilled Development Wells in 2016, and it expects to operate such wells during the remainder of the subordination period. Certain other Development Wells drilled by Chesapeake are currently operated by third-party operators. The failure of an operator to adequately perform operations could reduce production from the Underlying Properties and the cash available for distribution to Trust unitholders.

Because Chesapeake does not have a majority working interest in most of the non-operated properties comprising the Underlying Properties, Chesapeake may not be able to remove the operator in the event of poor or untimely performance. The failure of an operator to adequately perform operations could reduce the revenues distributable to the Trust and the amount of cash distributable to the Trust unitholders.

Production of oil, natural gas and NGL on the Underlying Properties could be materially and adversely affected by severe or unseasonable weather.

Production of oil, natural gas and NGL on the Underlying Properties could be materially and adversely affected by severe or unseasonable weather. Repercussions of severe weather conditions may include:

- evacuation of personnel and curtailment of operations;
- weather-related damage to facilities, resulting in suspension of operations;
- inability to deliver materials to worksites; and
- weather-related damage to pipelines and other transportation facilities.

Due to the Trust's lack of industry and geographic diversification, adverse developments in the Trust's existing area of operation could adversely impact its financial condition, results of operations and cash flows and reduce its ability to make distributions to the unitholders.

The Underlying Properties are operated for oil, natural gas and NGL production and are focused exclusively in the Colony Granite Wash in Washita County in the Anadarko Basin of western Oklahoma. This concentration could disproportionately expose the Trust's interests to operational and regulatory risk in that area. Due to the lack of diversification in industry type and location of the Trust's interests, adverse developments in the oil, natural gas and NGL markets or the area of the Underlying Properties, including, for example, transportation or treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance, could have a significantly greater impact on the Trust's financial condition, results of operations and cash flows than if the Royalty Interests were more diversified.

The generation of proceeds for distribution by the Trust depends in part on access to and the operation of gathering, transportation and processing facilities. Any limitation in the availability of those facilities could interfere with sales of oil, natural gas and NGL production from the Underlying Properties.

The amount of oil, natural gas and NGL that may be produced and sold from any well to which the Underlying Properties relate is subject to the availability of gathering, transportation and processing facilities. Even where such facilities are available, services from such facilities are subject to curtailment in certain circumstances, such as by reason of weather conditions, pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered

oil, natural gas and NGL to meet quality specifications of gathering lines or downstream transporters, excessive line pressure which prevents delivery or physical damage to the gathering system or transportation system. The curtailments may vary from a few days to several months. In many cases, Chesapeake or a third-party operator is provided limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If Chesapeake or a third-party operator is forced to reduce production due to such a curtailment, the revenues of the Trust and the amount of cash distributions to the Trust unitholders would similarly be reduced due to the reduction of proceeds from the sale of production. Moreover, Chesapeake currently ships all of its natural gas production from the Underlying Properties to market through one pipeline provider and sells all of its oil production from the Underlying Properties to one purchaser. Although Chesapeake currently does not have any material production shut-in and does not shut in production on a routine basis as a result of lack of accessibility to transportation or lack of processing facilities, there can be no assurance this will be the case in the future.

The Trust units may lose value and cash available for distribution may be reduced as a result of title deficiencies with respect to the Underlying Properties.

The existence of a title deficiency with respect to the Underlying Properties could reduce the value or render a property worthless, thus adversely affecting the distributions to unitholders. Chesapeake does not obtain title insurance covering oil, natural gas and mineral leaseholds. Chesapeake's inability or failure to cure title defects could cause Chesapeake to lose its rights to some or all production from some of the Underlying Properties, which could result in a reduction in proceeds available for distribution to unitholders and the value of the Trust units may be reduced.

The Trust is passive in nature and will have no stockholder voting rights in Chesapeake, managerial, contractual or other ability to influence Chesapeake, or control over the field operations of, sales of oil, natural gas and NGL from, or development of, the Underlying Properties.

Trust unitholders have no voting rights with respect to Chesapeake securities and will have no managerial, contractual or other ability to influence Chesapeake's activities or operations of the Underlying Properties. In addition, some of the Development Wells are currently operated by third parties unrelated to Chesapeake. Such third-party operators may not have the operational expertise of Chesapeake within the AMI. Oil and natural gas properties are typically managed pursuant to an operating agreement among the working interest owners in the properties. The typical operating agreement contains procedures whereby the owners of the aggregate working interest in the property designate one of the interest owners to be the operator of the property. Under these arrangements, the operator is typically responsible for making all decisions relating to drilling activities, sale of production, compliance with regulatory requirements and other matters that affect the property. Neither the Trustee nor the Trust unitholders have any contractual ability to influence or control the field operations of, sales of oil, natural gas and NGL from, or future development of, the Underlying Properties.

The oil, natural gas and NGL reserves estimated to be attributable to the Underlying Properties are depleting assets and production from those reserves will diminish over time. Furthermore, the Trust is precluded from acquiring other oil and natural gas properties or royalty interests to replace the depleting assets and production.

The proceeds payable to the Trust from the Royalty Interests are derived from the sale of the production of oil, natural gas and NGL from the Underlying Properties. The oil, natural gas and NGL reserves attributable to the Underlying Properties are depleting assets, which means that the reserves of oil, natural gas and NGL attributable to the Underlying Properties will decline over time. As a result, the quantity of oil, natural gas and NGL produced from the Underlying Properties will decline over time.

Future maintenance may affect the quantity of proved reserves that can be economically produced from the Underlying Properties to which the wells relate. The timing and size of these projects will depend on, among other factors, the market prices of oil, natural gas and NGL. Chesapeake has no contractual obligation to the Trust to make capital expenditures on the Underlying Properties in the future. Furthermore, for properties on which Chesapeake is not designated as the operator, Chesapeake has no control over the timing or amount of those capital expenditures. Chesapeake also has the right not to participate in the capital expenditures on properties for which it is not the operator, in which case Chesapeake and the Trust will not receive the production resulting from such capital expenditures. If Chesapeake or other operators of the wells to which the Underlying Properties relate do not

implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by Chesapeake or estimated in the reserve reports.

The Trust Agreement provides that the Trust's business activities are generally limited to owning the Royalty Interests and entering into the derivative contracts and activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the Royalty Interests. As a result, the Trust is not permitted to acquire other oil and natural gas properties or royalty interests to replace the depleting assets and production attributable to the Trust.

An increase in the differential between the prices realized by Chesapeake for oil, natural gas and NGL produced from the Underlying Properties and the NYMEX or other benchmark price of oil or natural gas could reduce the proceeds to the Trust and therefore the cash distributions by the Trust and the value of Trust units.

The prices received for Chesapeake's oil, natural gas and NGL production in Oklahoma usually fall below benchmark prices, such as NYMEX. The difference between the price received and the benchmark price is called a differential. The amount of the differential will depend on a variety of factors, including discounts based on the quality and location of hydrocarbons produced, btu content, post-production expenses and production taxes. These factors can cause differentials to be volatile from period to period. Chesapeake has little or no control over the factors that determine the amount of the differential, and cannot accurately predict natural gas or crude oil differentials. Increases in the differential between the realized price of oil, natural gas and NGL and the benchmark price for oil, natural gas and NGL could reduce the proceeds to the Trust and therefore the cash distributions by the Trust and the value of the Trust units.

The amount of cash available for distribution by the Trust will be reduced by post-production expenses and applicable taxes associated with the Royalty Interests, Trust expenses and incentive distributions payable to Chesapeake.

The Royalty Interests and the Trust will bear certain costs and expenses that will reduce the amount of cash received by or available for distribution by the Trust to the holders of the Trust units. These costs and expenses include the following:

- the Trust's share of the expenses incurred by Chesapeake to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and NGL (excluding costs of marketing services provided by Chesapeake);
- the Trust's share of applicable taxes on the oil, natural gas and NGL; and

- Trust administrative expenses, including fees paid to the Trustee and the Delaware Trustee, the annual administrative services fee payable to Chesapeake, tax return and Schedule K-1 preparation and mailing costs, independent auditor fees and registrar and transfer agent fees, costs associated with annual and quarterly reports to unitholders and certain internal expenses of the Trust incurred pursuant to the registration rights agreement.

In addition, the amount of funds available for distribution to unitholders will be reduced by the amount of any cash reserves maintained by the Trustee in respect of anticipated future Trust expenses.

Further, during the subordination period, Chesapeake will be entitled to receive a quarterly incentive distribution from the Trust equal to 50% of the amount by which cash available to be paid to all unitholders exceeds the incentive threshold for the applicable quarter.

The amount of costs and expenses borne by the Trust may vary materially from quarter to quarter. The extent by which the costs and expenses of the Trust are higher or lower in any quarter will directly decrease or increase the amount received by the Trust and available for distribution to the unitholders. Historical post-production expenses and taxes, however, may not be indicative of future post-production expenses and taxes.

The Trustee may, under certain circumstances, sell the Royalty Interests and dissolve the Trust; otherwise, the Trust will begin to liquidate following the end of the 20-year period in which the Trust owns the Term Royalties.

The Royalty Interests will be sold and the Trust will be dissolved upon the occurrence of certain events. For example, the Trustee must sell the Royalty Interests if unitholders approve the sale or vote to dissolve the Trust. The Trustee must also sell the Royalty Interests if cash available for distribution is less than \$1.0 million in each of any four consecutive quarters. The sale of all of the Royalty Interests will result in the dissolution of the Trust. Upon the dissolution

of the Trust, the net proceeds of any such sale, after the payment of Trust liabilities, will be distributed to the Trust unitholders pro rata and unitholders will not be entitled to receive any proceeds from the sale of production from the Underlying Properties following such date. If none of these events occur, the Trust will dissolve on the Termination Date.

In connection with the dissolution of the Trust on the Termination Date, the Term Royalties will automatically revert to Chesapeake, while the Perpetual Royalties will be sold and the proceeds will be distributed to the unitholders (including Chesapeake to the extent of any Trust units it owns) at the date the Trust dissolves or soon thereafter. The price received by the Trust from any purchaser of the Perpetual Royalties will depend, among other things, on the prices of oil, natural gas and NGL at that time. There can be no assurance that the prices of oil, natural gas and NGL will be at levels such that Trust unitholders will receive any particular amount of cash in return for the Trust's sale of the Perpetual Royalties.

Chesapeake will have a right of first refusal to purchase the Perpetual Royalties upon the dissolution of the Trust, which may reduce the inclination of third parties to place a bid, and thereby reduce the value received by the Trust in a sale. If the Trustee receives a bid from a proposed purchaser other than Chesapeake and wants to sell all or part of the Perpetual Royalties to such third party, the Trustee will be required to give notice to Chesapeake and identify the proposed purchaser and proposed sale price, and other terms of the bid.

The Trust is managed by a Trustee who cannot be replaced except at a special meeting of Trust unitholders.

The business and affairs of the Trust are managed by the Trustee. Voting rights as a Trust unitholder are more limited than those of stockholders of most public corporations. For example, there is no requirement for annual meetings of Trust unitholders, and the Trust does not currently anticipate holding annual meetings. Likewise, there is no requirement for an annual or other periodic re-election of the Trustee. The Trust Agreement provides that the Trustee may only be removed and replaced by the holders of a majority of the outstanding Trust units, excluding Trust units held by Chesapeake, voting in person or by proxy at a special meeting of Trust unitholders at which a quorum is present called by either the Trustee or the holders of not less than 10% of the outstanding Trust units. As a result, it may be difficult for public unitholders to remove or replace the Trustee without the cooperation of holders of a substantial percentage of the outstanding Trust units.

Trust unitholders have limited ability to enforce provisions of the Royalty Interest conveyances, and Chesapeake's liability to the Trust is limited.

The Trust Agreement permits the Trustee and the Trust to sue Chesapeake or any other future owner of the Underlying Properties to enforce the terms of the conveyances creating the Royalty Interests. If the Trustee does not take appropriate action to enforce provisions of these conveyances, a Trust unitholder's recourse would be limited to bringing a lawsuit against the Trust or the Trustee to compel the Trust or the Trustee to take specified actions. The Trust Agreement expressly limits a Trust unitholder's ability to directly sue Chesapeake or any other party other than the Trustee. As a result, Trust unitholders will not be able to sue Chesapeake or any future owner of the Underlying Properties to enforce the Trust's rights under the conveyances. Furthermore, the Royalty Interest conveyances prohibit recovery of certain types of damages, such as consequential and punitive damages, and provide that, except as set forth in the conveyances, Chesapeake will not be liable to the Trust for the manner in which it performs its duties in operating the Underlying Properties as long as it acts in good faith and in accordance with the reasonably prudent operator standard under the development agreement and, to the fullest extent permitted by law, will owe no fiduciary duties to the Trust or the unitholders.

Courts outside of Delaware may not recognize the limited liability of the Trust unitholders provided under Delaware law.

Under the Delaware Statutory Trust Act, Trust unitholders are entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under the General Corporation Law of the State of Delaware. No assurance can be given, however, that the courts in jurisdictions outside of Delaware will give effect to such limitation.

Chesapeake may sell Trust units in the public or private markets and such sales could have an adverse impact on the trading price of the common units.

Chesapeake owns an aggregate of 12,062,500 common units and 11,687,500 subordinated units. All of the subordinated units will automatically convert into common units at the end of the subordination period, which will occur

at the end of the 2017 second quarter. Chesapeake may sell Trust units in the public or private markets, and any such sales could have an adverse impact on the price of the common units or on any trading market that may develop. The Trust has granted registration rights to Chesapeake, which, if exercised, would facilitate sales of Trust units by Chesapeake to the public.

Conflicts of interest could arise between Chesapeake and the Trust.

Chesapeake could have interests that conflict with the interests of the Trust and the Trust unitholders. For example:

- Chesapeake's interests may conflict with those of the Trust and the Trust unitholders in situations involving the development, maintenance, operation or abandonment of the Underlying Properties. For example, Chesapeake may abandon a well that is no longer producing in paying quantities even though such well is still generating revenue for the Trust unitholders. Chesapeake may make decisions with respect to expenditures and decisions to allocate resources to projects in other areas that adversely affect the Underlying Properties, including reducing expenditures on these properties, which could cause oil, natural gas and NGL production to decline at a faster rate and thereby result in lower cash distributions by the Trust in the future.

Chesapeake may, without the consent or approval of the Trust unitholders, sell all or any part of its retained interest in the Underlying Properties, subject to and burdened by the Royalty Interests. Although Chesapeake must require any purchaser of its retained interest in the Underlying Properties to assume Chesapeake's obligations with respect to those properties, such sale may not be in the best interests of the Trust and the Trust unitholders. Any purchaser may lack Chesapeake's experience in the Colony Granite Wash or its creditworthiness.

Chesapeake may, without the consent or approval of the Trust unitholders, require the Trust to release Royalty Interests with an aggregate value of up to \$5.0 million during any 12-month period in connection with a sale by Chesapeake of a portion of its retained interest in the Underlying Properties. Although these releases are conditioned upon the Trust receiving an amount equal to the fair value to the Trust of such Royalty Interests, the fair value received by the Trust for such Royalty Interests may not fully compensate the Trust for the value of future production attributable to the Royalty Interests disposed of.

Chesapeake can sell its Trust units regardless of the effects such sale may have on common unit prices or on the Trust itself. Additionally, once Chesapeake is allowed to vote its Trust units, Chesapeake can vote its Trust units in its sole discretion.

In addition, Chesapeake has agreed that, if at any time the Trust's cash on hand (including available cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, it will lend funds to the Trust necessary to pay such expenses. Any such loan will be on an unsecured basis, and the terms of such loan will be substantially the same as those which would be obtained in an arms' length transaction between Chesapeake and an unaffiliated third party. If Chesapeake provides such funds to the Trust, it would become a creditor of the Trust and its interests as a creditor could conflict with the interests of unitholders. There were no loans outstanding as of December 31, 2016; however, in April 2016, Chesapeake loaned \$200,000 to the Trust. The loan was repaid in May 2016. As of December 31, 2015, a \$175,000 loan was outstanding with Chesapeake, and the loan was repaid in March 2016. In each case, Chesapeake agreed to permit the Trust to continue making distributions while the loan was outstanding.

Chesapeake may sell all or a portion of its retained interest in the Underlying Properties, subject to and burdened by the Royalty Interests; any such purchaser could have a weaker financial position and/or be less experienced in oil, natural gas and NGL development and production than Chesapeake.

Trust unitholders will not be entitled to vote on any sale by Chesapeake of its retained interest in the Underlying Properties and the Trust will not receive any proceeds from any such sale. The purchaser would be responsible for all of Chesapeake's obligations relating to the Royalty Interests on the portion of the Underlying Properties sold, including Chesapeake's obligation to operate the Underlying Properties sold in accordance with the Reasonably Prudent Operator Standard under the development agreement and Chesapeake's true-up obligations with respect to the Underlying Properties sold, and Chesapeake would have no continuing obligation to the Trust for those properties. Additionally, Chesapeake may enter into farmout or participation arrangements with respect to the wells burdened by the Royalty Interests. Any purchaser, farmout counterparty or participating partner could have a weaker financial position and/or be less experienced in oil, natural gas and NGL development and production in the Colony Granite Wash than

Chesapeake, which could result in a decrease in production from the Underlying Properties sold and a corresponding decrease in cash available for distribution to the Trust's unitholders. Additionally, in the event that Chesapeake enters into such a farmout or participation agreement, the Royalty Interests will not burden any interests that the counterparty earns under such an agreement.

Oil and natural gas drilling and producing operations can be hazardous and may expose Chesapeake to liabilities. Oil and natural gas operations are subject to many risks, including well blowouts, cratering and explosions, pipe failures, fires, formations with abnormal pressures, uncontrollable flows of oil, natural gas, brine or well fluids, oil spills, severe weather, natural disasters, groundwater contamination and other environmental hazards and risks. Some of these risks or hazards could materially and adversely affect Chesapeake's revenues and expenses by reducing or shutting in production from wells, loss of equipment or otherwise negatively impacting the projected economic performance of its prospects. For non-operated properties, Chesapeake is dependent on the operator for operational and regulatory compliance. A temporary or permanent halt of the production and sales of oil, natural gas and NGL at any of the Underlying Properties could also reduce Trust distributions by reducing the amount of proceeds available for distribution.

If any of these risks occurs, Chesapeake could sustain substantial losses as a result of:

- injury or loss of life;
- severe damage to or destruction of property, natural resources or equipment;
- pollution or other environmental damage;
- clean-up responsibilities;
- regulatory investigations and administrative, civil and criminal penalties; and
- injunctions resulting in limitation or suspension of operations.

A material event such as those described above could expose Chesapeake to liabilities, monetary penalties or interruptions in its business operations. While Chesapeake may maintain insurance against some, but not all, of the risks described above, its insurance may not be adequate to cover casualty losses or liabilities, and its insurance does not cover penalties or fines that may be assessed by a governmental authority. For certain risks, such as political risk, business interruption, war, terrorism and piracy, Chesapeake has limited or no insurance coverage. Also, in the future Chesapeake may not be able to obtain insurance at premium levels that justify its purchase. The occurrence of a significant event against which Chesapeake is not fully insured may expose them to liabilities.

The ability of the Underlying Properties to produce oil, natural gas and NGL economically and in commercial quantities could be impaired if Chesapeake is unable to acquire adequate supplies of water or is unable to dispose of or recycle the water it uses economically and in an environmentally safe matter.

Chesapeake's inability to secure sufficient amounts of water, or to dispose of or recycle the water used in its operations, could adversely impact development of the Underlying Properties. The imposition of new environmental initiatives and regulations, such as the Oklahoma Corporation Commission's volume reduction plans for oil and natural gas disposal wells injecting wastewater into the Arbuckle formation and the EPA's June 2016 pretreatment standards for wastewater, could further restrict Chesapeake's ability to conduct certain operations such as hydraulic fracturing or disposal of waste, including, but not limited to, produced water, drilling fluids and other materials associated with the development or production of oil and natural gas.

Potential legislative and regulatory actions addressing climate change could significantly impact the oil and gas industry and Chesapeake, causing increased costs and reduced demand for oil and natural gas.

Various state governments and regional organizations have considered enacting new legislation and promulgating new regulations governing or restricting the emission of greenhouse gases from stationary sources such as Chesapeake's equipment and operations. At the federal level, the EPA has already made findings and issued regulations that require Chesapeake to establish and report an inventory of greenhouse gas emissions. Additional legislative and/or regulatory proposals for restricting greenhouse gas emissions or otherwise addressing climate change could increase operating costs and could adversely affect demand for the oil and natural gas that Chesapeake sells. The potential increase in operating costs could include new or increased costs to obtain permits, operate and maintain equipment

and facilities, install new emission controls on equipment and facilities, acquire allowances to authorize greenhouse gas emissions, pay taxes related to greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Even without federal legislation or regulation of greenhouse gas emissions, states may pursue the issue either directly or indirectly.

In addition, the United States was actively involved in the United Nations Conference on Climate Change in Paris, which led to the creation of the Paris Agreement. The Paris Agreement will require countries to review and “represent a progression” in their nationally determined contributions, which set emissions reduction goals, every five years. The Paris Agreement could further drive regulation in the United States. Restrictions on emissions of methane or carbon dioxide that have been or may be imposed in various states, or at the federal level could adversely affect the oil and gas industry. Moreover, incentives to conserve energy or use alternative energy sources as a means of addressing climate change could reduce demand for oil and natural gas. Finally, we note that some scientists have concluded that increasing concentrations of greenhouse gases in the Earth's atmosphere may produce climate changes that have significant physical effects, such as higher sea levels, increased frequency and severity of storms, droughts, floods, and other climatic events. If any such effects were to occur, they could have an adverse effect on the results of operations of the underlying properties, which could result in a reduction in proceeds available for distribution to unitholders.

The Trustee has identified a material weakness in internal control over financial reporting. If the Trust fails to remediate this material weakness or otherwise fails to develop, implement and maintain appropriate internal control in future periods, its ability to report its financial condition and results of operations accurately and on a timely basis could be adversely affected.

The Trustee has identified a material weakness in internal controls over the review of the net investment in royalty interests and the accuracy of the non-cash impairment of net investment in royalty interests. Accordingly, the Trustee believes that, as of December 31, 2016, disclosure controls and procedures were not effective. The Trustee also determined that this material weakness existed as of March 31, 2016, June 30, 2016 and September 30, 2016. The specific material weakness and remediation efforts are described in Item 9A, Controls and Procedures. A “material weakness” is a deficiency, or a combination of deficiencies, in internal control over financial reporting, such that there is a reasonable possibility that a material misstatement of our annual or interim financial statements would not be prevented or detected on a timely basis. The Trust cannot assure that it will adequately remediate the material weakness or that additional material weaknesses in internal controls will not be identified in the future. Any failure to maintain or implement required new or improved controls, or any difficulties encountered in implementation, could result in additional material weaknesses, or could result in material misstatements in the financial statements. These misstatements could result in restatements of financial statements, cause the Trust to fail to meet reporting obligations or cause investors to lose confidence in reported financial information.

The Trust is in the process of remediating the identified material weakness in internal control, but the Trustee is unable at this time to estimate when the remediation effort will be completed. If the Trust fails to remediate this material weakness, there will continue to be an increased risk that future financial statements could contain errors that will be undetected. Further and continued determinations that there are material weaknesses in the effectiveness of internal control could reduce the accuracy of future financial statements. For more information relating to the Trustee's internal controls and disclosure controls and procedures, and the remediation plan undertaken by the Trust, see Item 9A, Controls and Procedures.

Tax Risks Related to the Units

The Trust's tax treatment depends on its status as a partnership for U.S. federal income tax purposes. If the IRS were to treat the Trust as a corporation for U.S. federal income tax purposes or the Trust were subjected to state or local entity level tax, then its cash available for distribution to Trust unitholders would be substantially reduced.

The anticipated after-tax economic benefit of an investment in the Trust units depends largely on the Trust being treated as a partnership for U.S. federal income tax purposes. The Trust has not requested, and does not plan to request, a ruling from the IRS on this or any other tax matter affecting it.

It is possible in certain circumstances for a publicly traded Trust otherwise treated as a partnership, such as the Trust, to be treated as a corporation for U.S. federal income tax purposes. Although the Trust does not believe based

upon its current activities that such treatment is applicable to it, a change in current law could cause it to be treated as a corporation for U.S. federal income tax purposes or otherwise subject it to taxation as an entity.

If the Trust were treated as a corporation for U.S. federal income tax purposes, it would pay federal income tax on its taxable income at the corporate tax rate, which is currently a maximum of 35%, and would likely be required to pay state income tax on its taxable income at the corporate tax rate in Oklahoma. Distributions to Trust unitholders would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to Trust unitholders without first being subjected to taxation at the entity level. Because a tax would be imposed upon the Trust as a corporation, its cash available for distribution to Trust unitholders would be substantially reduced. In addition, changes in current state law may subject the Trust to additional entity-level taxation by individual states. Because of state budget deficits and other reasons, several states have been evaluating ways to subject partnerships to entity-level taxation through the imposition of state income, franchise and other forms of taxation. Imposition of any such taxes may substantially reduce the cash available for distribution to Trust unitholders. Therefore, if the Trust were treated as a corporation for U.S. federal income tax purposes or otherwise subjected to a material amount of entity-level taxation, there would be a material reduction in the anticipated cash flow and after-tax return to the Trust unitholders, likely causing a substantial reduction in the value of the Trust units.

The Trust Agreement provides that if a law is enacted or existing law is modified or interpreted in a manner that subjects the Trust to taxation as a corporation or otherwise subjects it to entity-level taxation for U.S. federal, state or local income tax purposes, the subordination threshold amounts and the target distribution amounts may be adjusted to reflect the impact of that law on the Trust.

The U.S. federal income tax treatment of the Development Royalty Interest is not entirely free from doubt. A successful challenge by the IRS to the tax position the Trust takes with respect to the Development Royalty Interest could affect the amount, timing and character of income, gain or loss relating to an investment in Trust units.

The U.S. federal income tax laws and precedents applicable to the tax treatment of royalty interests in wells that will be drilled in the future are not well established. As a result, the tax treatment of the Development Royalty Interest is not entirely free from doubt. A successful challenge by the IRS to the tax position the Trust takes with respect to the Development Royalty Interest could negatively affect the amount, timing and character of income, gain or loss relating to a unitholder's investment in Trust units, which could increase or accelerate the amount of federal income tax payable on a unitholder's share of the Trust's income.

The tax treatment of an investment in Trust units could be affected by recent and potential legislative changes, possibly on a retroactive basis.

An individual having adjusted gross income in excess of \$200,000 (or \$250,000 for married taxpayers filing joint returns) is subject to the Net Investment Income Tax of 3.8% on the lesser of such excess or the individual's net investment income. For these purposes, net investment income generally includes interest income and royalty income derived from the Trust units as well as any net gain from the disposition of Trust units. In addition, currently the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals is 39.6% and 20%, respectively. It has been assumed that the effective rate of production tax on the oil, natural gas and NGL attributable to the Trust will be approximately 2.0% for the first three years of production for each well spudded on or after July 1, 2015, and approximately 7.0% thereafter. Moreover, these rates are subject to change by new legislation at any time.

The present U.S. federal income tax treatment of publicly traded partnerships, including the Trust, or an investment in the Trust units may be modified by administrative, legislative or judicial changes or differing interpretations at any time. For example, from time to time, the U.S. President and members of Congress propose and consider substantive changes to the existing federal income tax laws that affect publicly traded partnerships. Further, final regulations under Section 7704(d)(1)(E) of the Internal Revenue Code recently published in the Federal Register interpret the scope of the qualifying income requirements for publicly traded partnerships by providing industry-specific guidance. Any modification to the U.S. federal income tax laws may be applied retroactively and could make it more difficult or impossible for the Trust to meet the exception for certain publicly traded partnerships to be treated as partnerships for U.S. federal income tax purposes. The Trust is unable to predict whether any changes or other proposals will

ultimately be enacted, including as a result of fundamental tax reform. Any such changes could negatively impact the value of an investment in the Trust units.

If the IRS contests the tax positions the Trust takes, the value of the Trust units may be adversely affected, the cost of any IRS contest will reduce the Trust's cash available for distribution to Trust unitholders.