

CHESAPEAKE GRANITE WASH TRUST  
Form 10-K  
March 15, 2013  
Table of Contents

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, 2012

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

78701

(Address of principal executive offices)

(Zip Code)

(855) 802-1093

(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



Table of Contents

or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. [X]

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 [X]      Non-accelerated filer [ ]      Smaller reporting company [ ]  
(Do not check if a smaller reporting company)

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

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 \$19.69 on June 29, 2012, was approximately \$453 million.

As of March 14, 2013, 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

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Table of Contents2012 ANNUAL REPORT ON FORM 10-K  
TABLE OF CONTENTS

	Page
<b>PART I</b>	
Item 1. Business	<u>1</u>
Item 1A. Risk Factors	<u>25</u>
Item 1B. Unresolved Staff Comments	<u>43</u>
Item 2. Properties	<u>43</u>
Item 3. Legal Proceedings	<u>43</u>
Item 4. Mine Safety Disclosures	<u>43</u>
<b>PART II</b>	
Item 5. Market for Units of the Trust, Related Unitholder Matters and Trust Purchases of Units	<u>44</u>
Item 6. Selected Financial Data	<u>44</u>
Item 7. Trustee's Discussion and Analysis of Financial Condition and Results of Operations	<u>45</u>
Item 7A. Quantitative and Qualitative Disclosures About Market Risk	<u>51</u>
Item 8. Financial Statements and Supplementary Data	<u>54</u>
Item 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosure	<u>54</u>
Item 9A. Controls and Procedures	<u>73</u>
Item 9B. Other Information	<u>73</u>
<b>PART III</b>	
Item 10. Directors, Executive Officers and Corporate Governance	<u>74</u>
Item 11. Executive Compensation	<u>74</u>
Item 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters	<u>74</u>
Item 13. Certain Relationships and Related Transactions and Director Independence	<u>75</u>
Item 14. Principal Accountant Fees and Services	<u>77</u>
<b>PART IV</b>	
Item 15. Exhibits, Financial Statement Schedules	<u>78</u>

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.

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Table of Contents

**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. 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, NGL and natural gas 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,” “foresee,” “plan,” “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.

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## 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 45,400 gross acres (29,000 net acres) held by Chesapeake as of December 31, 2012.

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

**Bcf.** Billion cubic feet.

**Boe.** Barrel of oil equivalent, determined using the ratio of six mcf of natural gas to one bbl of oil, condensate or NGL, which approximates the relative energy content of oil, condensate and NGL as compared to natural gas. Despite holding the ratio constant at six mcf to one bbl, prices have historically often been higher for oil than natural gas on an energy equivalent basis, although there have been periods in which they have been lower.

**Btu.** British thermal unit, which is the quantity of heat required to raise the temperature of one pound of water one degree Fahrenheit.

**Completion.** The process of treating a drilled well followed by the installation of permanent equipment for the production of oil, NGL and natural gas, or in the case of a dry well, the 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.

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**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 (i) through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well and (ii) through installed extraction equipment and infrastructure operational at the time of the reserves estimate if the extraction is by means not involving a well.

**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 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 (i) 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, (ii) 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, (iii) 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 (iv) provide improved recovery systems.

**Development Well.** As defined by the SEC, a development well is a well that is 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 or are to be 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 a natural gas or oil 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 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.

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

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

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 boe.

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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 of Future Net Revenues ("PV-10"). The present value of estimated future net revenue to be generated from the production of proved reserves, discounted using an annual discount rate of 10% (as required by the SEC), calculated without deducting future income taxes. 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 federal income tax expense, the PV-10 and Standardized Measure attributable to the Royalty Interests are the same. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Underlying Properties or the Royalty Interests. The Trust, Chesapeake and others in the oil and gas industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. PV-10 for the Royalty Interests has been calculated without deduction for production and development costs, as the Trust will not bear those costs.

Price Differential. The difference in the price of natural gas or oil 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.

(i) 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, NGL and natural gas produced. Examples of production expenses (sometimes called lifting expenses) are:

(A) Costs of labor to operate the wells and related equipment and facilities.

(B) Repairs and maintenance.

- (C) Materials, supplies, and fuel consumed and supplies utilized in operating the wells and related equipment and facilities.
  - (D) Property taxes and insurance applicable to proved properties and wells and related equipment and facilities.
  - (E) Production taxes.
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(ii) 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, NGL and natural gas reserves are those quantities of oil, NGL 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 (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil on the basis of available geoscience and engineering data. In the absence of information 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 (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole, the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price 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 such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions.

**Proved Undeveloped Reserves.** 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 the 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 such techniques have been proved effective by actual projects in the same reservoir or an analogous reservoir, or by other evidence using reliable technology establishing reasonable certainty.

PV-10. See “Present value of future net revenues.”

Reserves. Estimated remaining quantities of oil, NGL 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,

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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 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 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. Standardized measure differs from PV-10 because standardized measure includes the effect of future income taxes on future net revenues. Because the Trust does not bear income taxes, PV-10 and standardized measure with respect to the 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.

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Table of Contents

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, the telephone number of the Trustee is (855) 802-1093.

The Trustee maintains a website for filings by the Trust with the Securities and Exchange Commission (the “SEC”). Electronic filings by the Trust with the SEC are available free of charge through the Trust's website at [www.chkgranitewashtrust.com](http://www.chkgranitewashtrust.com) or through the SEC's website at [www.sec.gov](http://www.sec.gov). The Trust will also provide electronic and paper copies of its recent filings free of charge upon request to the Trustee.

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 interest in the Producing Wells (the “PDP Royalty Interest”) entitles 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, NGL and natural gas production attributable to Chesapeake's net revenue interest in the Producing Wells. The royalty interest in the Development Wells (the “Development Royalty Interest”) entitles 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, NGL and natural gas production attributable to Chesapeake's net revenue interest in the Development Wells.

Through an initial public offering in November 2011, the Trust sold 23,000,000 of its common units representing beneficial interests in the Trust to the public for net proceeds, after payment of offering expenses, of approximately \$409.7 million. 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 and as of December 31, 2012, 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.

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, NGL and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by affiliates of Chesapeake. Cash distributions to unitholders will be increased or decreased by the effect of the Trust's derivative contracts and reduced by the Trust's general and administrative expenses. See Derivative Contracts below.

## Table of Contents

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 will 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, NGL and natural gas 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, NGL and natural gas sold from the Underlying Properties, the prices received for such sales, when Chesapeake receives payment for such sales, payments 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, over time target distributions decline as a result of the depletion of the reserves in the Underlying Properties.

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 constitutes 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 the 80% of the target distribution for the corresponding quarter (the "subordination threshold"). 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.

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 (each, an "incentive threshold"). The remaining 50% of cash available for distribution in excess of the incentive thresholds will be paid to Trust unitholders, including Chesapeake, on a pro rata basis.

At the end of the fourth full calendar quarter following Chesapeake's satisfaction of its drilling obligation with respect to the Development Wells, 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 fourth full quarter after Chesapeake's satisfaction of its drilling obligation with respect to the Development Wells, 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."

Table of Contents

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 <sup>(1)</sup> (\$ per unit)	Incentive Threshold <sup>(1)</sup>
2012:		
Fourth Quarter <sup>(2)</sup>	0.67	1.01
2013:		
First Quarter	0.69	1.04
Second Quarter	0.69	1.04
Third Quarter	0.71	1.07
Fourth Quarter	0.69	1.04
2014:		
First Quarter	0.69	1.04
Second Quarter	0.68	1.02
Third Quarter	0.69	1.03
Fourth Quarter	0.66	0.99
2015:		
First Quarter	0.66	0.99
Second Quarter	0.68	1.02
Third Quarter	0.64	0.96
Fourth Quarter	0.56	0.84
2016:		
First Quarter	0.51	0.76
Second Quarter	0.47	0.70
Third Quarter	0.44	0.66
Fourth Quarter	0.41	0.62
2017:		
First Quarter	0.39	0.59
Second Quarter	0.37	0.56

(1) For each quarter, the subordination threshold equals 80% of the target distribution and the incentive threshold equals 120% of the target distribution. The subordination and incentive thresholds terminate after the distribution is made for the fourth full calendar quarter following Chesapeake's completion of its drilling obligation.

(2) A distribution of \$0.6700 per common unit and \$0.3772 per subordinated unit was paid on March 1, 2013 to unitholders of record as of February 19, 2013.

The aggregate distributions paid in the twelve months ended December 31, 2012 were \$2.6265 per common unit and \$2.0892 per subordinated unit. The first two distributions, paid on March 1, 2012 and May 31, 2012, were above the subordination threshold and below the incentive threshold for the corresponding distribution period. However, the distributable income available for distribution to unitholders with respect to the distributions paid on August 30, 2012 and November 29, 2012 were below the applicable subordination thresholds, resulting in a payment of \$0.6100 per common unit and \$0.4819 per subordinated unit on August 30, 2012 and a payment of \$0.6300 per common unit and \$0.2208 per subordinated unit on November 29, 2012. As of March 14, 2013, Chesapeake owned 12,062,500 common units and all 11,687,500 subordinated units, which together represent 50.8% of the outstanding Trust units.

Table of Contents

## Derivative Contracts

The Trust uses derivative instruments to manage its exposure to variability in cash flow from changes in oil and NGL prices. On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering approximately 50% of the expected oil and NGL production and approximately 37% of the expected revenue (based on NYMEX strip oil prices as of October 28, 2011) attributable to the Royalty Interests from October 1, 2011 through September 30, 2015. To the extent oil production falls below the hedged oil volume, the derivative contracts will also cover NGL production. To the extent oil and NGL prices are not correlated, the derivative contracts will not effectively mitigate the price risk of the Trust's NGL production. The remaining estimated production of oil and NGL during that time, all production of natural gas during that time and all production after such time, will not be hedged, except in connection with the restructuring of an existing derivative contract. The derivative contracts are not qualified for hedge accounting treatment, and therefore all future mark-to-market fluctuations will be recorded to the Trust Corpus until cash settled. The value of the derivative contracts as of December 31, 2012, was a liability of \$8.1 million.

These commodity derivative contracts consist of fixed-price oil swaps, in which the Trust receives a fixed price and pays a floating market price, based on NYMEX settlement prices, to the counterparty for the underlying commodity of the derivative. As a party to these contracts, the Trust will receive payments directly from its counterparty or be required to pay any amounts owed directly to its counterparty. All swaps are net settled based on the difference between the fixed-price payment and the floating-price payment. Settlements are due on a quarterly basis, including the first two months of the calendar quarter just ended and the last month of the calendar quarter prior to that one. Any payment due to or from such counterparty will be made by the 40th day following the end of the calendar quarter in which such payments become due. See Note 3 to the financial statements contained in Part II Item 8 of this Annual Report for further discussion of the derivative contracts.

Under the derivative contracts and separate from the drilling obligation under the development agreement, there is a requirement that Chesapeake drill and complete, or cause to be drilled and completed, a specified number of wells (inclusive of the Producing Wells as of the completion of the initial public offering and Development Wells) by the end of each six-month period ending June 30 and December 31 during the term of the derivative contracts. Specifically, from November 16, 2011 until June 30, 2016, the derivative contracts require that Chesapeake drill and complete, cause to be drilled and completed or participate as a non-operator in the drilling of the wells in accordance with the drilling plan set forth in the following table:

Reference Period End Date	Cumulative Minimum Well Requirement
December 31, 2012	69
June 30, 2013	78
December 31, 2013	85
June 30, 2014	90
December 31, 2014	97
June 30, 2015	108
December 31, 2015	111
June 30, 2016	117

Chesapeake's drilling plan, which provides for the ratable drilling of the Development Wells during the development period, contemplates drilling more wells in each six-month period than the drilling obligation under the derivative contracts requires. As of December 31, 2012, Chesapeake has drilled and completed 120 gross wells that count towards the cumulative minimum well requirement under the derivative contracts.

In addition, with respect to each such six-month period, the Trust is required to deliver to the counterparty and the collateral agent under the derivative contracts (a) an independent reserve engineers' report that sets forth the total reserves estimated to be attributable to the Trust's interest in the Underlying Properties as of the end of such period and such other information as is typically included in, or required under SEC rules to be included in, summary reserve engineers reports and (b) a report that sets forth certain information regarding the Development Wells drilled and completed as of the end of such six-month period.

## Table of Contents

The Trust's obligations to the counterparty under the derivative contracts are secured by proved reserves attributable to the Trust's interest in the Underlying Properties. The counterparty's obligations under the hedging arrangement must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts owed to the Trust exceeds defined thresholds. Subject to any applicable notice and cure periods, if, among other things, the Trust or Chesapeake is in material default of the drilling, payment or reporting requirements under the derivative contracts, becomes subject to bankruptcy proceedings or the Trust becomes subject to certain change of control transactions, the hedging counterparty may foreclose on the lien on the Royalty Interests. Even if such foreclosure is solely a result of Chesapeake's action or omission, the Trust may have no remedy against Chesapeake. In addition, the derivative contracts contain a prohibition on the Trust granting additional liens on any of its properties, other than customary permitted liens and liens in favor of the Trustee or the Delaware Trustee. Under the Trust Agreement, the Trustee may create a cash reserve to pay for future expenses of the Trust.

### 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 will also be 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. As hedge manager, Chesapeake also has authority to terminate, restructure or otherwise modify all or any portion of the Trust's derivative contracts to the extent that Chesapeake reasonably determines, acting in good faith, that the volumes hedged under such contracts exceed, or are expected to exceed, the combined estimated production attributable to the Royalty Interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake is not acting as a fiduciary for the Trust and has no affirmative duty to modify any of the Trust's derivative contracts, except as required by the derivative contracts. Moreover, under the Trust Agreement, Chesapeake is indemnified by the Trust for any actions it takes in this regard.

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.

Distributions and Income Computations. The Trust makes 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. In addition, any payments due from or required to be made to the counterparty under the Trust's derivative contracts are paid within 40 days of the end of

Table of Contents

such 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 Securities Exchange Act of 1934, as amended, 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.

6

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## Table of Contents

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, the development agreement and the Drilling Support Lien (except with respect to certain matters that do not adversely affect the right 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, NGL and natural gas 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, Drilling Support Lien and administrative services agreement. The assets of the Trust consist of the Royalty Interests, the derivative contracts 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.

## Table of Contents

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 Securities Exchange Act of 1934, as amended, 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 and derivative contracts. 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 "Assets of the Trust", interests acquired in connection with foreclosure under the Drilling Support Lien and cash and temporary cash investments, and it may not engage in any investment activity except investing cash on hand. Chesapeake, acting as

hedge manager for the Trust, may cause the Trust to restructure existing derivative contracts in certain circumstances.

8

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## Table of Contents

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;
- foreclose on the Drilling Support Lien if Chesapeake does not satisfy its drilling obligation on or before June 30, 2016, and contract with a third-party operator to drill any remaining Development Wells, and transfer a portion of the Trust's assets in connection therewith;
- 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;
- 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; or
- in connection with a foreclosure on the Drilling Support Lien.

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.

## Table of Contents

**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 is a party to derivative contracts and the Trust previously has had, and in the future could have, payment obligations under such arrangements. Otherwise, the Trust does not 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, 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 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.

**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, which is June 30, 2031, 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., 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 on November 14, 2011 in connection with the offering of its common units to the public (the "Federal Income Tax Considerations Section in the Prospectus"). However, as

## Table of Contents

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 IRS regarding its United States federal income tax reporting positions and its positions may not be sustained by a court or if contested by the IRS.

The material federal income tax considerations that may be relevant to certain Trust unitholders were discussed in the Federal Income Tax Considerations Section in the Prospectus. Unitholders and prospective unitholders should review the Federal Income Tax Considerations Section in the Prospectus.

## Competition and Markets

The oil and gas industry is highly competitive. Chesapeake competes with both major integrated and other independent oil and gas companies in acquiring desirable leasehold acreage, producing properties and the equipment and expertise necessary 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. The oil and gas industry also faces competition from alternative fuel sources, including other fossil fuels such as coal and imported liquefied natural gas. Competitive conditions may be affected by future legislation and regulations as the U.S. 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, NGL and natural gas production, such as changing prices, domestic and foreign policy conditions, weather conditions, the price and availability of alternative fuels, the proximity and capacity of pipelines and other transportation facilities, and overall economic conditions. 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.

Future price fluctuations of oil, NGL and natural gas will 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, NGL and natural gas, neither the Trust nor Chesapeake can make reliable predictions of future supply and demand for oil, NGL and natural gas, future oil, NGL and natural gas prices or the effect of future oil, NGL and natural gas prices on the Trust.

## Environmental Matters and Regulation

General. All of Chesapeake's operations are conducted onshore in the United States. The U.S. oil, NGL and natural gas industry is regulated at the federal, state and local levels, and some of the laws, rules and regulations that govern its operations carry substantial penalties for noncompliance. These regulatory burdens increase Chesapeake's cost of doing business and, consequently, affect its profitability.

Regulation of Oil and Natural Gas Operations. The laws and regulations applicable to Chesapeake's exploration and production operations include requirements for permits 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 regulations include, but are not limited to:

- the location of wells;
- the method of drilling and completing wells;
- the surface use and restoration of properties upon which wells are drilled;
- water withdrawal;
- the plugging and abandoning of wells;
- the disposal of fluids used or other wastes generated in connection with operations;
- the marketing, transportation and reporting of production; and
- the valuation and payment of royalties.

Chesapeake's operations 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, including Oklahoma, allow the forced pooling or integration of tracts to facilitate exploration, while other states, such as Texas 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

Table of Contents

therefore, more difficult to fully develop a project if the operator owns less than 100% of the leasehold. In addition, state conservation laws establish maximum rates of production from oil and natural gas wells, generally prohibit the venting or flaring of natural gas and impose certain requirements regarding the ratatability of production. The effect of these regulations is to limit the amount of oil, NGL and natural gas Chesapeake can produce and to limit the number of wells and the locations at which it can drill.

Chesapeake operates a number of natural gas gathering systems. The U.S. Department of Transportation and certain state agencies regulate the safety and operating aspects of the transportation and storage activities of these facilities. There is currently no price regulation of the company's sales of oil, NGL and natural gas, although governmental agencies may elect in the future to regulate certain sales.

Chesapeake does not anticipate that compliance with existing laws and regulations governing exploration, production and natural gas gathering will have a material adverse effect upon its capital expenditures, earnings or competitive position.

Environmental, Health and Safety Regulation. The business operations of Chesapeake and its ownership and operation of oil, NGL and natural gas interests are subject to various federal, state and local environmental, health and safety laws and regulations pertaining to the release, emission or discharge of materials into the environment, the generation, storage, transportation, handling and disposal of materials (including solid and hazardous wastes), the safety of employees, or otherwise relating to pollution, preservation, remediation or protection of human health and safety, natural resources, wildlife or the environment. Chesapeake must take into account the cost of complying with environmental regulations in planning, designing, constructing, drilling, operating and abandoning wells and related surface facilities. In most instances, the regulatory frameworks relate to the handling of drilling and production materials, the disposal of drilling and production wastes, and the protection of water and air. In addition, Chesapeake's operations may require it to obtain permits for, among other things,

- air emissions;
- the construction and operation of underground injection wells to dispose of produced saltwater and other non-hazardous oilfield wastes; and
- the construction and operation of surface pits to contain drilling muds and other non-hazardous fluids associated with drilling operations.

Delays in obtaining permits, an inability to obtain new permits or revocation of Chesapeake's current permits due to noncompliance could result in the imposition of fines and could inhibit Chesapeake's ability to drill the remaining Development Wells or continue production from the Producing Wells and completed Development Wells.

Federal, state and local laws may require Chesapeake to remove or remediate previously disposed wastes, including wastes disposed of or released by Chesapeake or prior owners or operators in accordance with current laws or otherwise, to suspend or cease operations at contaminated areas, or to perform 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, or 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 responsible for releases of a hazardous substance into the environment. These persons include the owner or operator of the site where the release occurred, and persons that disposed of or arranged for the disposal of hazardous substances at 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 to seek to recover from responsible classes of persons the costs of such actions.

Other federal and state laws, in particular the federal Resource Conservation and Recovery Act, or RCRA, regulate hazardous and non-hazardous solid wastes. In the course of its operations, Chesapeake generates petroleum hydrocarbon wastes and ordinary industrial wastes. Under a longstanding legal framework, certain of these wastes are not subject to federal regulations governing hazardous wastes, though they may be regulated under other federal and state laws. Chesapeake believes it is in substantial compliance with all regulations regarding the handling and disposal of oil and gas exploration and production wastes from its operations, including with respect to the Underlying Properties. 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.

Table of Contents

Chesapeake's operations are subject to the federal Clean Air Act and comparable state laws and regulations. These laws and regulations regulate emissions of air pollutants from various industrial sources, including compressor stations, and impose various monitoring and reporting requirements. The EPA issued New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that amend existing NSPS and NESHAP standards for oil and natural gas facilities as well as create new NSPS standards for oil and natural gas production, transmission and distribution facilities.

The Federal Water Pollution Control Act, or the Clean Water Act, and analogous state laws impose restrictions and strict controls regarding the discharge of pollutants into state waters as well as waters of the U.S. The placement of material into jurisdictional water or wetlands of the U.S. is prohibited, except in accordance with the terms of a permit issued by the United States Army Corps of Engineers. The discharge of pollutants into regulated waters is prohibited, except in accordance with the terms of a permit issued by the EPA or a state agency delegated with EPA's authority. Further, Chesapeake's corporate policy prohibits discharge of produced water to surface waters. Spill prevention, control and countermeasure requirements of federal laws 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 Clean Water Act and analogous state laws require individual permits or coverage under general permits for discharges of storm water runoff from certain types of facilities.

The Oil Pollution Act of 1990, or OPA, establishes strict liability for owners and operators of facilities that are the site of a release of oil into waters of the U.S. 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 U.S.

Federal and state occupational safety and health laws require Chesapeake to organize and maintain information about hazardous materials used, released or produced in its operations. Certain portions of this information must be provided to employees, state and local governmental authorities and local citizens. Chesapeake is also subject to the requirements and reporting set forth in federal workplace standards.

Chesapeake has made and will continue to make expenditures to comply with environmental, health and safety regulations and requirements. These are necessary business costs in the oil and natural gas industry. Although Chesapeake is not fully insured against all environmental, health and safety risks, and Chesapeake's insurance does not cover any penalties or fines that may be issued by a governmental authority, it maintains insurance coverage which it believes is customary in the industry. Moreover, it is possible that other developments, such as stricter and more comprehensive environmental, health and safety laws and regulations, as well as claims for damages to property or persons, resulting from company operations, could result in substantial costs and liabilities, including civil and criminal penalties, to Chesapeake. Chesapeake believes that it is in material compliance with existing environmental, health and safety regulations. It believes that the cost of maintaining compliance with these existing regulations will not have a material adverse effect on its business, financial position and results of operation, but new or more stringent regulations could increase the cost of doing business and could have a material adverse effect on the proceeds available to the Trust. Moreover, accidental releases or spills may occur in the course of Chesapeake's operations on the Underlying Properties causing Chesapeake to incur significant costs and liabilities, including for third-party claims for damage to property and natural resources or personal injury.

**Hydraulic Fracturing.** Vast quantities of oil, NGL and natural gas deposits exist in deep shale and other unconventional formations. It is customary in Chesapeake's industry to recover these resources from these deep formations through the use of hydraulic fracturing combined with horizontal drilling. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in deep underground formations using water, sand and other additives pumped under high pressure into the formation. These formations are generally geologically separated and isolated from fresh ground water supplies by thousands of feet of impermeable rock layers. Chesapeake views hydraulic fracturing as a means to increase the production of almost every well that Chesapeake drills and completes.

Chesapeake follows applicable legal requirements for groundwater protection in its operations that are subject to supervision by state and federal regulators. Furthermore, Chesapeake's well construction practices include 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.

Injection rates and pressures are monitored instantaneously and in real time at the surface during Chesapeake's hydraulic fracturing operations. Pressure is monitored on both the injection string and the immediate annulus to the injection string. Hydraulic fracturing operations are shut down immediately if an abrupt change occurs to the injection

## Table of Contents

pressure or annular pressure. These aspects of well construction are designed to eliminate a pathway for the fracturing fluid to contact any aquifers during the hydraulic fracturing operations.

Hydraulic fracture stimulation requires the use of water. Chesapeake uses fresh water in fracturing treatments in accordance with applicable water management plans and laws. Chesapeake strives to find alternative sources of water and minimize its reliance on fresh water resources. Chesapeake has technical staff dedicated to the development of water recycling and re-use systems, and Chesapeake's Aqua Renew<sup>®</sup> program uses state-of-the-art technology in an effort to recycle produced water in its operations.

Produced, or formation, water is a naturally occurring by-product of natural gas and liquids extraction. Chesapeake disposes of produced formation water in Class II underground injection control wells, which are designed and permitted to place the water into deep geologic formations, isolated from fresh water sources. These Class II wells are overseen by the EPA pursuant to the Underground Injection Control Program.

Some states have adopted, and other states are considering adopting, regulations that impose disclosure requirements on hydraulic fracturing operations. Since early 2011, Chesapeake has voluntarily participated in FracFocus, a national publicly accessible web-based registry developed by the Ground Water Protection Council and the Interstate Oil and Gas Compact Commission, with support of the U.S. Department of Energy, to report on a well-by-well basis the additives and chemicals and amount of water used in the hydraulic fracturing process for each of the wells we operate. The website, [www.fracfocus.org](http://www.fracfocus.org), also includes information about how hydraulic fracturing works, the chemicals used in hydraulic fracturing and how fresh water aquifers are protected. Some states, including Oklahoma, mandate disclosure of chemical additives used in hydraulic fracturing require operators to use the FracFocus website for reporting.

Legislative, regulatory and enforcement efforts, as well as guidance from regulatory agencies, at the federal level and in some states have been initiated to require or make more stringent the permitting and compliance requirements for hydraulic fracturing operations. Hydraulic fracturing is typically regulated by state oil and gas commissions. However, the EPA recently asserted federal regulatory authority over hydraulic fracturing involving diesel fuels under the Safe Drinking Water Act's Underground Injection Control Program, and has published proposed guidance documents regarding the process for obtaining a permit for hydraulic fracturing involving diesel fuel. Chesapeake believes such permitting would not materially affect its operations because it does not use diesel fuel in connection with hydraulic fracturing operations. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, and published an update in December 2012. The EPA guidance, including its definition of diesel fuel, the related litigation, EPA's study, and other analysis by federal and state agencies to assess the impacts of hydraulic fracturing could each spur further action toward federal legislation and regulation of hydraulic fracturing activities. Also, for the second consecutive session, legislation has been introduced in Congress is considering legislation to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process.

Oklahoma's regulations were reviewed and received positive approval from the State Review of Oil & Natural Gas Environmental Regulations. Despite this finding, the Oklahoma Corporation Commission adopted amendments to its oil and natural gas rules that will require operators of hydraulically fractured wells to disclose the contents of fluids injected into each such well. The new disclosure rules became effective on July 1, 2012 and apply to horizontal wells hydraulically fractured after the end of 2012 and all wells hydraulically fractured after the end of 2013. As Chesapeake already discloses this information to FracFocus, these new requirements should not have a significant impact on the operation of the Underlying Properties. If additional laws or regulations that significantly restrict hydraulic fracturing are adopted at the Oklahoma state level, such legal requirements could make it more difficult or costly for Chesapeake to perform fracturing to stimulate production in the Underlying Properties and thereby affect the determination of whether a well is commercially viable. In addition, if hydraulic fracturing is regulated at the federal level, Chesapeake's fracturing activities, including with respect to its operations at the Underlying Properties, could become subject to additional permit requirements or operational restrictions and also to associated permitting delays and potential increases in costs.

Restrictions on hydraulic fracturing could make it prohibitive for Chesapeake to conduct operations and also reduce the amount of oil, NGL and natural gas 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.

## Table of Contents

**Global Warming and Climate Change.** Various state governments and regional organizations are considering 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. 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, NGL and natural gas that Chesapeake sells. The potential increase in Chesapeake's operating costs could include new or increased costs to obtain permits, operate and maintain its equipment and facilities, install new emission controls on its equipment and facilities, acquire allowances to authorize its greenhouse gas emissions, pay taxes related to its greenhouse gas emissions and administer and manage a greenhouse gas emissions program. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for oil, NGL and natural gas.

### **Operating Hazards and Insurance**

The exploration and production 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 \$75 million control of well policy 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 \$425 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. 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. The insurance coverage that Chesapeake maintains 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 agreement related to properties from which the Royalty Interests were conveyed. The AMI consists of approximately 45,400 gross acres (29,000 net acres). As of December 31, 2012, the total reserves estimated to be attributable to the Trust were 28,203 mboe (46.1% oil and NGL by volume). This amount includes 16,714 mboe of proved developed reserves and 11,489 mboe of proved undeveloped 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 oil and NGL production currently generates more revenue than natural gas production in the Colony Granite Wash due to prices that have historically been, and currently are, significantly higher for oil and NGL than for natural gas. Development costs for horizontal wells drilled and completed in the AMI averages approximately \$12.96 per boe, which is comparable to the development costs for other large-scale resource developments in the Mid-Continent in which Chesapeake operates.

Chesapeake began drilling horizontal wells in the Colony Granite Wash in 2007. As of December 31, 2012, Chesapeake is the largest leaseholder in the Colony Granite Wash, with approximately 43,200 net acres (of which

Table of Contents

approximately 29,000 net acres are subject to the Royalty Interests), the most active driller in the play, based on rig count, and produces the highest volumes from the Colony Granite Wash. Since 2007, there have been 227 Des Moines horizontal wells drilled in the Colony Granite Wash. Of those 227 wells, Chesapeake has drilled 181 wells and participated in another 38 wells. As of March 8, 2013, there were four rigs drilling horizontal wells in the AMI, all of which were drilling for Chesapeake. While horizontal wells are more expensive than vertical wells, a horizontal well increases the production of hydrocarbons and adds significant recoverable reserves per well. In addition, an operator can achieve better returns on drilling investments with horizontal drilling because the production from one horizontal well is typically equal to the production from several vertical wells. While Chesapeake is the most active company in this play, as of March 8, 2013, other operators in the Colony Granite Wash include publicly-listed companies such as Penn Virginia Corporation, Apache Corporation, QEP Resources, Inc., SM Energy Company and Marathon Oil Corporation and privately-held companies such as Samson Resources, Chaparral Energy, Inc. and Ward Petroleum Corporation.

**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, 2012, the Trust on average owns a 47.6% net revenue interest in the Producing Wells and a 28.9% net revenue interest in the completed Development Wells. Chesapeake retains 10% of the proceeds from the sales of oil, NGL and natural gas 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, NGL and Natural Gas 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.

The pre-tax present value of estimated future net revenue is intended to represent the current market value of the estimated oil, NGL and natural gas reserves owned by the Trust. All of the Trust's estimated oil, NGL and natural gas reserves are located within the U.S.

The table below sets forth information as of December 31, 2012 with respect to the estimated proved reserves of the Underlying Properties and the Royalty Interests and the PV-10. Because the Trust will not bear federal 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, NGL and natural gas reserves attributable to the Royalty Interests. The reserve estimates were prepared by Ryder Scott Company, L.P. ("Ryder Scott") in accordance with the criteria established by the SEC.

	Proved Reserves				PV-10 (000s)
	Oil (mdbl)	NGL (mdbl)	Gas (mmcf)	Total (mboe)	
Underlying Properties:					
Developed	2,715	9,491	95,398	28,106	\$ 328,106

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Undeveloped	3,959	7,934	80,857	25,369	102,236
Total	6,674	17,425	176,255	53,475	\$430,342
Royalty Interests:					
Developed	1,708	5,635	56,224	16,714	\$238,814
Undeveloped	1,865	3,566	36,348	11,489	204,090
Total	3,573	9,201	92,572	28,203	\$442,904

16

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Table of Contents

The proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil, NGL and natural gas for the period from January 1, 2012 through December 1, 2012, 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 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)	NGL (per bbl)	Natural gas (per mcf)
Trailing 12-month average (SEC) pricing	\$ 94.84	\$ 94.84	\$ 2.76
Weighted average wellhead price (Underlying Properties)	\$ 90.88	\$ 32.72	\$ 1.61
Weighted average wellhead prices (Royalty Interests)	\$ 90.89	\$ 33.21	\$ 1.60

As of December 31, 2012, the reserve estimates for the Royalty Interests included 11,489 mboe of reserves classified as proved undeveloped ("PUD"), compared to 24,300 mboe as of December 31, 2011. Presented below is a summary of changes in our proved undeveloped reserves for 2012.

	Total (mboe)
Proved undeveloped reserves, beginning of period	24,300
Extensions, discoveries and other additions	1,181
Revisions of previous estimates <sup>(1)</sup>	(1,049 )
Developed	(9,637 )
Deleted	(3,306 )
Purchase of reserves-in-place	—
Proved undeveloped reserves, end of period	11,489

(1) This amount represents 1,051 mboe of downward price-related revisions and 2 mboe of other upward revisions. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves.

As of December 31, 2012, there were no PUDs that had remained undeveloped for five years or more. Chesapeake invested approximately \$231 million in the Underlying Properties in 2012 to convert 21,474 mboe of PUDs to proved developed reserves. All the costs were paid by Chesapeake as the Trust is not responsible for the cost of development. The \$204 million PV-10 attributable to the estimated PUDs of the Royalty Interests has been calculated assuming that Chesapeake will expend approximately \$319 million to develop these reserves: \$123 million in 2013, \$116 million in 2014 and \$80 million in 2015 and beyond. The amount and timing of these expenditures will depend on a number of factors, including actual drilling results, availability of drilling and related services, service costs, commodity prices and the availability of capital. Chesapeake's developmental drilling schedule for the remaining Development Wells is subject to revision and reprioritization throughout the year resulting from unknowable factors such as rig availability, title issues or delays, and Chesapeake's net revenue interest in each Development Well when drilled and completed. The proved reserves as of December 31, 2012 include only PUD locations which are immediate offsets to producing wells.

The annual net decline rate on producing properties is projected to be 35% from 2013 to 2014, 23% from 2014 to 2015, 18% from 2015 to 2016 and 15% from 2016 to 2017. As of December 31, 2012, of the total proved reserves, 28,106 mboe and 16,714 mboe attributable to the Underlying Properties and the Royalty Interests, respectively, were classified as proved developed producing.

Chesapeake's ownership interest used in calculating proved reserves and the associated estimated future net revenue was determined after giving effect to the assumed maximum participation by other parties to Chesapeake's farmout

and participation agreements. The prices used in calculating the estimated future net revenues attributable to proved reserves are based on historical prices, as required by the SEC and do not reflect market prices for oil, NGL

Table of Contents

and natural gas production sold subsequent to December 31, 2012. The estimated proved reserves may not be produced and sold at the assumed prices.

The Trust's estimated proved reserves and the standardized measure of discounted future net cash flows of the proved reserves at December 31, 2012, and the changes in quantities and standardized measure of such reserves since January 1, 2012, are shown in Note 8 of the notes to the financial statements included in Item 8 of this Annual Report. 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, NGL and natural gas that cannot be measured in an exact way, 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, NGL and natural gas 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 is obligated to drill, cause to be drilled or participate as a non-operator in the drilling of 118 Development Wells by June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to producing in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake retained or will retain an interest in each of the Producing Wells and Development Wells and, as of March 8, 2013, Chesapeake operated approximately 95% of the Producing Wells and the 56 completed Development Wells (approximately 61.3 Development Wells as calculated under the development agreement) and expects to operate approximately 90% of the remaining Development Wells through the completion of its drilling obligation. Until such time as Chesapeake has met its commitment to drill the Development Wells, Chesapeake will not drill or complete, and will not permit any other person within its control to drill or complete: (i) any well in the Colony Granite Wash formation or lease acreage included within the AMI for its own account; or (ii) any well that will have 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 54.4%. 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, NGL and natural gas resulting from the drilling of the Development Wells.

Chesapeake is credited for drilling one full Development Well if the perforated length of the well is equal to or greater than 3,500 feet and Chesapeake's net revenue interest in the well is equal to 52.0%. For wells with a perforated length that is less than 3,500 feet, and for wells in which Chesapeake has a net revenue interest greater than or less than 52.0%, Chesapeake receives proportionate credit. Given that Chesapeake's actual net revenue interest in each Development Well may be greater than or less than 52.0% and the perforated length of each well drilled may be less than 3,500 feet, Chesapeake may be required to drill more or less than 118 wells in order to fulfill its drilling obligation. As of December 31, 2012, Chesapeake had drilled and completed 51 wells within the AMI (approximately 55.1 Development Wells as calculated under the development agreement). Chesapeake's drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. The drilling schedule provides that approximately 30 wells are expected to be drilled and completed each year until the drilling obligation is fulfilled. As of March 8, 2013, Chesapeake had drilled and completed a total of 56 wells in the AMI (approximately 61.3 Development Wells as calculated under the development agreement) and had drilled, or caused to be drilled, two additional wells in the AMI that were awaiting completion.

In drilling the Development Wells, Chesapeake is required to adhere to the Reasonably Prudent Operator Standard. Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the remaining Development Wells will be generally consistent with those used for the Producing Wells and the completed Development Wells.

Table of Contents

Chesapeake may, and anticipates that it will, rely on third-party operators to fulfill a portion of its drilling, completion and equipping obligation. The Trust will not bear any of the costs of drilling, completing and equipping the Development Wells. Until Chesapeake has satisfied its drilling obligation, it will not be permitted to drill or complete any well in the Colony Granite Wash formation on lease acreage included within the AMI for its own account. 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 fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned are released from the Drilling Support Lien and the total dollar amount that may be recovered by the Trust for Chesapeake's failure to fulfill its drilling obligation is proportionately reduced. As of March 8, 2013, the total dollar amount that may be recovered is approximately \$126.3 million

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.

Well Locations. Chesapeake has approximately 180 remaining potential drilling locations within the AMI, based on assumed spacing of four wells per 640-acre section, and may drill some of the Development Wells on units that encompass land controlled by third-party operators in order to maximize recovery in the field and also maximize the perforated length of each Development Well drilled.

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.

	2012		2011		2010	
	Gross	Net	Gross	Net	Gross	Net
Wells Drilled:						
Development productive	40	28	20	13	10	6
Exploratory productive	—	—	5	4	6	5
Dry	—	—	—	—	—	—
Total	40	28	25	17	16	11

Table of Contents

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, 2012. A significant percentage 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 Acreage <sup>(1)</sup>		Undeveloped Acreage <sup>(2)</sup>	
	Gross	Net	Gross	Net
Acreage Held by Chesapeake within the AMI	40,236	26,195	5,121	2,807

(1) Gross and net developed acres are acres spaced or assignable to productive wells. The drilling unit for each Colony 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.

(2) 1,780 net acres are not held by production as of December 31, 2012. Of these, 959 net acres will expire in 2013, 656 net acres will expire in 2014 and 165 net acres will expire in 2015.

Prior to fulfilling its drilling obligation to the Trust, Chesapeake may, at its sole discretion, cause the Trust to exchange leased acreage in the AMI for other leased acreage in the sections adjacent to the AMI (such adjacent sections are referred to as the "Development Area"). If additional acreage in the Development Area becomes subject to the Royalty Interests, then the AMI will automatically expand to include such acreage. In addition, if Chesapeake acquires any additional leases or interests in the AMI, Chesapeake may make such additional leases or interests subject to the Royalty Interests with respect to any Development Wells subsequently drilled on such acreage. However, the aggregate acreage attributable to the exchanged leases or additional leases or acreage may not exceed five percent of the acreage initially subject to the Royalty Interests and the reserve profile of the newly burdened acreage must be consistent with the reserve profile of the acreage released by the Trust.

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, NGL and natural gas 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, Inc. ("CEMI"), a wholly owned subsidiary of Chesapeake, markets the majority of Chesapeake's operated production. CEMI enters into oil, NGL and natural gas sales arrangements with large aggregators of supply and these arrangements may be on a month-to-month basis or may be for a term of up to one year or longer. The oil, NGL and natural gas are sold at market prices and subsequently any applicable post-production expenses will be deducted. CEMI 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, NGL and natural gas 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, NGL and natural gas production attributable to Chesapeake's remaining interest in the Underlying Properties.

Post-production expenses are deducted from proceeds paid to the Trust. Access Midstream Partners, L.P. ("ACMP"), successor to previously affiliated Chesapeake Midstream Partners, L.P. (Chesapeake had a 46% equity investment until June 2012), provides gathering, treating, compression and other post-production services and other third parties, including Enogex LLC ("Enogex") and Plains Exploration & Production Company ("Plains"), provide 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, NGL and natural gas prior to payment being made to Chesapeake or CEMI for such production. At other times, Chesapeake or CEMI 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 CEMI 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.

Table of Contents

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, NGL and natural gas 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 ACMP under a contract that expires in approximately 17 years. NGL and natural gas are processed at facilities owned by Enogex 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 ACMP or transported by trucks owned by third parties and sold to Plains. In the event of a loss of its contracts with ACMP, Enogex or Plains, Chesapeake believes that the availability of other customers and service providers in the area is sufficient to accommodate such loss. Chesapeake also believes that the capacity of interstate pipelines is sufficient to accommodate the increased production of oil, NGL and natural gas from the Underlying Properties as currently contemplated.

Chesapeake has entered into, and expects to continue to enter into, oil, NGL and natural gas supply arrangements and post-production service arrangements for the oil, NGL and natural gas to be produced from the remaining Development Wells that are similar to those in place with respect to the Producing Wells and completed Development Wells. Any new oil, NGL and natural gas 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 was conveyed. Chesapeake began drilling horizontal wells in the Colony Granite Wash in 2007.

The following table provides revenues and direct operating expenses for the years ended December 31, 2012, 2011 and 2010, derived from the Underlying Properties' statements of revenues and direct operating expenses.

	Years Ended December 31,		
	2012	2011	2010
	(\$ in thousands)		
Oil, NGL and natural gas revenues <sup>(1)</sup>	\$ 176,875	\$ 172,705	\$ 168,347
Direct operating expenses:			
Production expenses excluding taxes	12,835	8,252	5,542
Production taxes	2,437	3,887	3,271
Ad valorem taxes	43	43	27
Total direct operating expenses	15,315	12,182	8,840
Revenues in excess of direct operating expenses	\$ 161,560	\$ 160,523	\$ 159,507

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

Table of Contents

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, 2012, 2011 and 2010.

	Years Ended December 31,		
	2012	2011	2010
Production:			
Oil (mbbls)	993	843	870
NGL (mbbls)	1,999	1,435	1,494
Natural gas (mmcf)	19,137	13,572	14,713
Total production (mboe)	6,182	4,540	4,816
Average sales prices: <sup>(1)</sup>			
Oil (per bbl)	\$90.42	\$89.98	\$76.06
NGL (per bbl)	\$29.57	\$42.09	\$36.28
Natural gas (per mcf)	\$1.46	\$2.69	\$3.26
Production expenses (per boe) <sup>(2)</sup>	\$2.08	\$1.82	\$1.16
Production taxes (per boe) <sup>(3)</sup>	\$0.39	\$0.86	\$0.68

(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 (i) volume produced and (ii) prices received for production.

Oil, NGL and Natural Gas Revenues. For the year ended December 31, 2012, oil, NGL and natural gas revenues were \$176.9 million compared to \$172.7 million and \$168.3 million for the years ended 2011 and 2010, respectively. The \$4.2 million increase in revenues from 2011 to 2012 was primarily due to an increase in production of 1,642 mboe and a slight increase in oil prices of \$0.44 per bbl, from \$89.98 per bbl to \$90.42 per bbl. These increases were offset by a decrease in the average sales price for NGL and natural gas from \$42.09 to \$29.57 for NGL and from \$2.69 to \$1.46 for natural gas. The \$4.4 million increase in revenue from 2010 to 2011 was primarily due to an increase in the average sales price for oil and NGL from \$76.06 to \$89.98 per bbl for oil and from \$36.28 to \$42.09 per bbl for NGL, offset by a production decrease of 276 mboe and a decrease in the sales price received for natural gas from \$3.26 to \$2.69 per mcf.

Production Expenses. For the year ended December 31, 2012, production expenses, excluding ad valorem taxes, were \$12.8 million compared to \$8.3 million and \$5.5 million for the years ended 2011 and 2010, respectively. The year-over-year increases were primarily due to an increase in the number of producing wells. On a unit-of-production basis, production expenses were \$2.08 per boe in 2012 compared to \$1.82 and \$1.16 per boe in 2011 and 2010, respectively.

Production Taxes. For the year ended December 31, 2012, production taxes were \$2.4 million compared to \$3.9 million and \$3.3 million for the years ended 2011 and 2010, respectively. On a unit-of-production basis, production taxes were \$0.39 per boe in 2012 compared to \$0.86 and \$0.68 per boe in 2011 and 2010, respectively. In general, production taxes are calculated using value-based formulas that produce higher per unit costs when oil, NGL and natural gas prices are higher. The \$1.5 million decrease in production taxes from 2011 to 2012 was primarily due to a decrease in the average sales price for oil, NGL and natural gas from \$38.04 to \$28.61 per boe. The \$0.6 million increase in production taxes from 2010 to 2011 was primarily due to an increase in the average sales price for oil, NGL and natural gas from \$34.95 to \$38.04 per boe, offset by a production decrease of 276 mboe.

The Reserve Reports for the Underlying Properties and the Royalty Interests

The oil, NGL and natural gas reserves in this Annual Report were estimated by Ryder Scott. The process to review and estimate the reserves began with Chesapeake's Reservoir Engineering 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 was reviewed by various levels of Chesapeake management for accuracy before consultation with Ryder Scott. Ryder Scott was consulted with regularity during the

Table of Contents

reserve estimation process to review properties, assumptions, and any new data available. Internal reserve estimates and methodologies were compared to Ryder Scott's estimates and methodologies to test the reserve estimates and conclusions before the reserve estimates were included in this Annual Report. Additionally, Chesapeake's senior management reviewed and approved the reserve reports contained herein.

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

- 37 years of practical experience in petroleum engineering with 34 years of this experience being in the estimation and evaluation of reserves;
- certified professional engineer in the state of Oklahoma;
- Bachelor of Science degree in Petroleum Engineering; and
- member in good standing of the Society of Petroleum Engineers.

Chesapeake ensures that the key members of Chesapeake's Reserve Engineering Department have appropriate technical qualifications to oversee the preparation of reserves estimates, including, with respect to its engineers, an undergraduate degree in petroleum engineering from an accredited university or, with respect to its engineering technicians, a minimum of a four-year degree in mathematics, economics, finance or other 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 determine and report proved reserves. Reserves estimates are made by experienced reservoir engineers or under their direct supervision.
- Chesapeake's Reservoir Engineering Department reviews all of Chesapeake's and the Trust's reported proved reserves at the close of each quarter.
- Each quarter, Chesapeake's Reservoir Engineering Department managers, Chesapeake's Vice President of Corporate Reserves, the Executive Vice President of Production and Chief Operating Officer review all significant reserves changes and all new proved undeveloped reserves additions.
- Chesapeake's Reservoir Engineering Department reports independently of any of Chesapeake's operating divisions.

Technologies. The reserve reports were 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. The proved undeveloped locations within the AMI are generally all offsets to the horizontal wells drilled and producing as of December 31, 2012.

Ryder Scott. Ryder Scott, the independent petroleum engineering consultant, estimated all of the proved reserve information in this Annual Report, in accordance with the definitions and regulations of the SEC and conform to the FASB Accounting Standards Codification Topic 932, Extractive Activities-Oil and Gas. For the purposes of the

reserve reports, Ryder Scott used technical and economic data including, but not limited to, well test data, production data, historical price and cost information, and property ownership interests. The reserves in the reserve reports have been estimated using deterministic methods. Ryder Scott used standard engineering and geosciences methods, or a combination of methods, such as performance analysis and analogy, that they considered to be appropriate and necessary to categorize and estimate reserves in accordance with SEC definitions and regulations. A substantial portion of these reserves are for undeveloped locations and producing wells that lack sufficient production history upon which performance-related estimates of reserves can be based. Therefore, these reserves are based on estimates of reservoir volumes and recovery efficiencies along with analogy to properties with similar geologic and reservoir characteristics. Ryder Scott's expertise is in petroleum engineering, geoscience, and petrophysical interpretation, not

Table of Contents

legal or accounting matters; they are not accountants, attorneys, or landmen. As in all aspects of oil and gas evaluation, there are uncertainties inherent in the interpretation of engineering and geoscience data; therefore, the conclusions from Ryder Scott necessarily represent only informed professional judgment. The titles to the properties have not been examined by Ryder Scott, nor has the actual degree or type of interest owned been independently confirmed. The data used in Ryder Scott's estimates were obtained from Chesapeake and the non-confidential files of Ryder Scott and were accepted as accurate. Supporting geoscience, field performance, and work data are on file in their office. The qualifications of the technical person at Ryder Scott primarily responsible for overseeing the estimate of the reserves include: 30 years of practical experience in the estimation and evaluation of petroleum reserves; a registered professional engineer in the state of Texas; and a Bachelor of Science degree in Electrical Engineering. These qualifications meet or exceed the Society of Petroleum Engineers standard requirements to be a professionally qualified Reserve Estimator and Auditor. Ryder Scott are independent petroleum engineers, geologists, geophysicists, and petrophysicists; Ryder Scott does not own an interest in these properties and are not employed on a contingent basis.

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.

Table of Contents

ITEM 1A. Risk Factors

Risks Related to the Units

Drilling for and producing oil, NGL and natural gas on the Underlying Properties are high risk activities with many uncertainties that could delay the anticipated drilling schedule for the Development Wells and adversely affect future production from the Underlying Properties. Any such delays or reductions in production could decrease cash available for distribution to unitholders.

The drilling and completion of the Development Wells are subject to numerous risks beyond Chesapeake's and the Trust's control, including risks that could delay or change the current drilling schedule for the Development Wells and the risk that drilling will not result in commercially viable oil, NGL and natural gas production. Drilling for oil, NGL and natural gas can be unprofitable if dry wells are drilled and 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 will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations and the costs of drilling, completing and operating wells are often uncertain before drilling commences. Drilling and production operations on the Underlying Properties may be curtailed, delayed or canceled as a result of various factors, including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including permitting;
- unusual or unexpected geological formations and miscalculations or irregularities in formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- 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;
- unexpected operational events and drilling conditions;
- pipe or cement failures and casing collapses;
- pressures, fires, blowouts and explosions;
- lost or damaged drilling and service tools;
- loss of drilling fluid circulation;
- lack of sufficient water or water disposal facilities in connection with hydraulic fracturing;
- uncontrollable flows of oil, NGL and natural gas water or drilling fluids;
- natural disasters;
- environmental hazards, such as oil, NGL or natural gas 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, NGL and natural gas prices or, for hedged production, increases in pricing differentials; and
- title problems affecting the Underlying Properties.

If drilling of Development Wells is delayed or 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.

In addition, Development Wells may not be successful and Chesapeake is not obligated to drill replacement wells if this occurs. Under the development agreement, Chesapeake will receive credit for drilling a Development Well if the well is drilled in the AMI and perforated horizontally for completion in the Colony Granite Wash, even if such well

does

25

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## Table of Contents

not successfully produce hydrocarbons. Additionally, once Chesapeake plugs and abandons an unsuccessful Development Well that well will be released from the Drilling Support Lien.

Prices of oil, NGL and natural gas fluctuate due to a number of factors that are beyond the control of the Trust and Chesapeake, and lower prices could reduce proceeds to the Trust, Chesapeake's economic incentive to drill and cash distributions to unitholders.

The Trust's reserves and quarterly cash distributions are highly dependent upon the prices realized from the sales of oil, NGL and natural gas. The markets for these commodities are very volatile. Oil, NGL and natural gas prices can fluctuate widely in response to a variety of factors that are beyond the control of the Trust and Chesapeake. These factors include, among others:

- regional, domestic and foreign supply, and perceptions of supply, of oil, NGL and natural gas;
- the price and level of foreign imports of oil, NGL and natural gas, including political instability or armed conflict in producing regions;
- U.S. and worldwide political and economic conditions;
- the level of demand, and perceptions of demand, for oil, NGL and natural gas;
- weather conditions and seasonal trends;
- anticipated future prices of oil, NGL, natural gas, alternative fuels and other commodities;
- technological advances affecting energy consumption and energy supply;
- the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
- natural disasters;
- the nature and extent of domestic and foreign governmental regulations and taxation;
- energy conservation and environmental measures;
- the price and availability of alternative fuels and energy sources; and
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls.

For oil, from 2007 through March 8, 2013, the highest monthly NYMEX settled price was \$134.62 per bbl and the lowest was \$33.87 per bbl. For natural gas, from 2007 through March 8, 2013, the highest monthly NYMEX settled price was \$13.11 per mmbtu and the lowest was \$2.04 per mmbtu. In addition, the market price of oil, NGL and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil, NGL and natural gas for heating purposes during the winter season. Historically high levels of NGL and natural gas production in 2012 resulted in lower prices for those commodities throughout 2012 and in the beginning of 2013.

Lower oil, NGL and natural gas prices will reduce proceeds to which the Trust is entitled and may ultimately reduce the amount of oil, NGL and natural gas 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, NGL and natural gas 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, NGL and natural gas 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, NGL and natural gas 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, NGL and natural gas prices also reduces the accuracy of target distributions used to calculate the subordination and incentive thresholds. There can be no assurance that the Trust's derivative contracts will mitigate these risks.



Table of Contents

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. It is not possible to measure underground accumulations of oil, NGL and natural gas in an exact way and estimating reserves has uncertainty. Ultimately, actual production and revenues for the Underlying Properties could be materially less than estimated amounts. Petroleum engineers are required to make subjective estimates of underground accumulations of oil, NGL and natural gas based on factors and assumptions that include:

- historical production from the area compared with production rates from other producing areas;
- oil, NGL and natural gas prices, production levels, btu content, production expenses, transportation costs, production and excise taxes and capital expenditures; and
- the assumed effect of governmental regulation.

Changes in these assumptions or actual production expenses incurred and results of actual development could materially decrease reserve estimates.

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. 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.

As with all horizontal drilling programs, there is a risk that some or all of a horizontal well could miss the target reservoir. As a result, the Trust may not receive the benefit, or any revenue from, some or all of the proved undeveloped reserves reflected in the reserve reports, notwithstanding the fact that Chesapeake has satisfied its drilling obligation.

Chesapeake's ability to satisfy its obligations to the Trust depends on its financial position, and in the event of a default by Chesapeake in its obligation to drill the Development Wells or 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 is obligated to drill and complete, or participate as a non-operator in the drilling and completion of, the Development Wells at its own expense. Chesapeake expects to operate approximately 90% of the remaining Development Wells until the completion of its drilling obligation. As of March 8, 2013, Chesapeake operates 95% of the Producing Wells and completed Development Wells. The conveyances provide that Chesapeake is obligated to market, or cause to be marketed, the oil, NGL and natural gas 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 these obligations will depend on its future financial condition, economic performance, access to capital, ability to sell assets and ability to comply with the financial covenants contained in its debt instruments, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on the Drilling Support Lien to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the Trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation and the maximum amount the Trust can recover in a foreclosure or other action is limited to approximately

Table of Contents

\$126.3 million as of March 8, 2013, which is the estimated amount of the Trust's share of the costs of drilling the remaining Development Wells and is not indicative of the total costs that will actually be incurred in drilling those wells. The maximum amount that the Trust can recover will be reduced proportionately as each Development Well is completed and released from the Drilling Support Lien and will not be adjusted for general inflation or inflation in oilfield service costs. There can be no assurance that the value of Chesapeake's interests in the undeveloped portions of the AMI secured by the Drilling Support Lien will be equal to the amount recoverable at any given time, and such interests may be worth considerably less. The process of foreclosing on such collateral may be expensive and time-consuming and delay the drilling and completion of the Development Wells; such delays and expenses would reduce Trust distributions by reducing the amount of proceeds available for distribution and may result in the loss of acreage due to leasehold expirations. Any amounts actually recovered in a foreclosure action would be applied to completion of Chesapeake's drilling obligation, would not result in any distribution to the Trust unitholders and may be insufficient to drill the number of wells needed for the Trust to realize the full value of the Royalty Interests in Development Wells. Furthermore, the Trust would have to seek a new party to perform the drilling and operations of the wells. The Trust may not be able to find a replacement driller or operator, and it may not be able to enter into a new agreement with such replacement party on favorable terms within a reasonable period of time. As long as the Royalty Interests are pledged as collateral to the Trust's hedging counterparty, the Trust's arranging for a replacement driller or operator may be more difficult or impossible. In such an event, the production from the Trust's properties would decline and such decline may trigger a foreclosure on the Royalty Interests by the hedging counterparty. The possibility of this foreclosure could deter the Trust from exercising its right to foreclose on the Drilling Support Lien.

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 Trust's ability to foreclose on the Drilling Support Lien, and 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. A delay in realizing on the collateral for the Drilling Support Lien is possible, and it cannot be guaranteed that a bankruptcy court would permit such foreclosure. It is possible that the bankruptcy would also delay the execution of a new agreement with another driller or operator. If the Trust enters into a new agreement with a drilling or operating partner, the new partner might not achieve the same levels of production or sell oil, NGL and natural gas at the same prices as Chesapeake was able to achieve.

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 recently 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.

Table of Contents

Estimates of the target distributions to unitholders used to calculate the subordination thresholds and incentive thresholds are 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 are based on assumptions about drilling, production, oil, NGL and natural gas 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 assume that oil, NGL and natural gas production is 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 may not increase at this rate or at all and may instead decline, as they have for natural gas. Additionally, these estimates assume that the Development Wells will be drilled on Chesapeake's current anticipated schedule and the related Underlying Properties will achieve production volumes set forth in the reserve reports included in the Prospectus; however, the drilling of the Development Wells may be delayed and actual production volumes may be significantly lower. Further, after wells are completed, production operations may be curtailed, delayed or terminated as a result of a variety of risks and uncertainties, including those described above under "Drilling for and producing oil, NGL and natural gas on the Underlying Properties are high risk activities with many uncertainties that could delay the anticipated drilling schedule for the Development Wells and adversely affect future production from the Underlying Properties. Any such delays or reductions in production could decrease cash available for distribution to unitholders."

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. To the extent actual production volumes or sales prices of oil, NGL and natural gas differ from the assumptions used to generate the target distributions, the actual distributions Trust unitholders receive may 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. Additionally, the subordination period will terminate and the subordinated units will convert into common units at the end of the fourth full calendar quarter following Chesapeake's completion of its drilling obligation. Depending on the prices at which Chesapeake is able to sell volumes attributable to the Trust, the common units may receive a distribution that is below the subordination threshold.

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 drill Development Wells where Chesapeake is not the operator.

Pursuant to the development agreement between Chesapeake and the Trust, Chesapeake is obligated to drill and complete, or cause to be drilled and completed, the equivalent of 118 Development Wells in the AMI of which approximately 61.3 Development Wells (as calculated under the development agreement) had been drilled and completed as of March 8, 2013. Chesapeake has drilled, or caused to be drilled, two additional wells in the AMI that are awaiting completion as of March 8, 2013. Chesapeake owns a majority working interest in approximately 90% of

Table of Contents

the locations on which it expects to drill the remaining Development Wells, and it expects to operate such wells during the subordination period. In order to satisfy its drilling obligation, Chesapeake will rely upon third-party operators to drill some of the Development Wells. A significant portion of these wells may be drilled by a single third-party operator. The ability of third-party operators to help Chesapeake meet the drilling obligation will depend on those operators' future financial condition and economic performance and access to capital, which, in turn, will depend upon the supply and demand for oil and natural gas, prevailing economic conditions and financial, business and other factors. 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. Chesapeake may be provided little or no notice by these operators that they are failing to drill the Development Wells in accordance with pre-existing schedules.

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. If the Development Wells take longer to be drilled than currently anticipated, this may delay revenue earned from the production of oil and natural gas by such wells. The revenues distributable to the Trust and the amount of cash distributable to the Trust unitholders would similarly be delayed.

For those Development Wells where Chesapeake is the operator, Chesapeake may rely on third party service providers to conduct the drilling operations.

Although Chesapeake owns substantial oilfield service assets, where Chesapeake is the operator of a Development Well, it may rely on third-party service providers to perform the necessary drilling operations. The ability of third-party service providers to perform such drilling operations will depend on those service providers' financial condition and economic performance and access to capital, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors. The failure of a third-party service provider to adequately perform operations could delay drilling or completion or reduce production from the Underlying Properties and the cash available for distribution to Trust unitholders. If the Development Wells take longer to be drilled and completed than currently anticipated, this may delay revenue earned from the production of oil, NGL and natural gas by such wells. The revenues distributable to the Trust and the amount of cash distributable to the Trust unitholders would similarly be delayed.

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

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

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

Shortages or increases in costs of equipment, services and qualified personnel could delay the drilling of the Development Wells and result in a reduction in the amount of cash available for distribution.

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and natural gas industry can fluctuate significantly, often in correlation with oil, NGL and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These

factors also cause significant increases in costs for equipment, services and personnel. Higher oil, NGL and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly hinder Chesapeake's ability to perform the drilling obligation and delay completion of the Development Wells, which would reduce future distributions to Trust unitholders.

Table of Contents

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, NGL and natural gas production only 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, NGL and natural gas 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, NGL and natural gas production from the Underlying Properties.

The amount of oil, NGL and natural gas 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, NGL and natural gas 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.

Some of the Development Wells on the Underlying Properties may be drilled in locations that currently are not serviced by gathering and transportation pipelines or locations in which existing gathering and transportation pipelines do not have sufficient capacity to transport additional production. As a result, Chesapeake may not be able to sell the production from certain Development Wells until the necessary gathering systems and/or transportation pipelines are constructed or until the necessary transportation capacity on an interstate pipeline is obtained. Any delay in the procurement of additional transportation capacity would delay the receipt of any proceeds that may be associated with production from the Development Wells.

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, gas and mineral leaseholds. Additionally, undeveloped leasehold acreage has greater risk of title defects than developed acreage.

Prior to the drilling of a Development Well, Chesapeake intends to obtain a drilling title opinion to identify defects in title to the leasehold. Frequently, as a result of such examinations, certain curative work may be required to correct identified title defects, and such curative work entails time and expense. Chesapeake's inability or failure to cure title defects could render some locations undrillable or 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.

Table of Contents

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, NGL and natural gas 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 will be 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 has any contractual ability to influence or control the field operations of, sales of oil, NGL and natural gas from, or future development of, the Underlying Properties.

The oil, NGL and natural gas 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, NGL and natural gas from the Underlying Properties. The oil, NGL and natural gas reserves attributable to the Underlying Properties are depleting assets, which means that the reserves of oil, NGL and natural gas attributable to the Underlying Properties will decline over time. As a result, the quantity of oil, NGL and natural gas 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, NGL and natural gas. With the exception of Chesapeake's commitment to drill the Development Wells, 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 price realized by Chesapeake for oil, NGL and natural gas 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, NGL and natural gas 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, NGL and natural gas and the benchmark price for oil, NGL and natural gas could reduce the proceeds to the Trust and therefore the cash distributions by the Trust and the value of the Trust units.

Table of Contents

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, NGL and natural gas (excluding costs of marketing services provided by Chesapeake);
- the Trust's share of applicable taxes on the oil, NGL and natural gas;
- 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; and
- any amount owed to the counterparty under the Trust's derivative contracts.

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 derivative contracts for the Trust cover only a portion of the production attributable to the Royalty Interests, such arrangements limit the Trust's ability to benefit from commodity price increases for hedged volumes, and such arrangements are secured by the Royalty Interests and may require the Trust to make cash payments in excess of its receipts.

The Trust hedged approximately 50% of the expected oil and NGL production and approximately 37% of the Trust's expected revenues (based on NYMEX strip oil prices as of October 28, 2011) for the production periods from October 1, 2011 through September 30, 2015 under its derivative contracts. To the extent oil production falls below the hedged oil volume, the derivative contracts will also cover NGL production. Such estimated production will be hedged using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. Since late 2011, NGL prices have decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the hedging arrangements will not effectively mitigate the price risk of the Trust's NGL production. Except in limited circumstances involving the restructuring of an existing derivative contracts, the remaining estimated production of oil and NGL and all production of natural gas from October 1, 2011 through September 30, 2015 will not be hedged and the Trust will not have the ability to enter into additional derivative contracts, terminate existing derivative contracts or hedge production beyond September 30, 2015. With respect to unhedged volumes and periods, the Trust will not be protected against the price risks inherent in holding interests in oil, NGL and natural gas, commodities that are frequently characterized by significant price volatility. Furthermore, while the use of derivative contracts limits the downside risk of price declines, they may also limit the Trust's ability to benefit from increases in oil and NGL prices above the fixed price of the derivative contract on the portion of the production attributable to the Royalty Interests that is hedged.

Chesapeake acts as hedge manager to the Trust pursuant to the administrative services agreement. In fulfilling its role as hedge manager, Chesapeake does not act as a fiduciary for the Trust, does not have an affirmative duty to modify any of the Trust's derivative contracts except as required by the derivative contracts, and does not have any liability to the Trust in connection with Chesapeake's failure to modify, or any affirmative modification of, any of the

## Table of Contents

Trust's derivative contracts. Moreover, Chesapeake will be indemnified by the Trust for any actions it takes in this regard.

The Trust's receipt of any payments due to it based on the derivative contracts depends upon the financial position of the counterparty. If the counterparty to the derivative contracts was to default on its obligations to make payments under such contracts, the cash distributions to the Trust unitholders would likely be materially reduced as the derivative contract payments are intended to provide additional cash to the Trust during periods of lower oil and NGL prices.

If actual production, over which the Trust has no control, is below the amounts forecasted in the reserve reports and oil or NGL prices rise, the derivative contracts entered into by the Trust may result in the Trust having to make cash payments under the derivative contracts which could, in certain circumstances, be significant. Swap contracts entered into between the Trust and the counterparty provide the Trust with the right to receive from the counterparty the excess of the fixed-price specified in the derivative contract over a floating market price, multiplied by the volume of production hedged. If the floating market price exceeds the specified fixed-price, the Trust must pay the counterparty this difference in price multiplied by the volume of production hedged, even if the production attributable to the Royalty Interests is insufficient to cover the volume of production specified in the applicable derivative contracts. Accordingly, if the production attributable to the Royalty Interests is less than the volume hedged and the floating market price exceeds the specified fixed-price, the Trust will have to make payments against which it will have insufficient offsetting cash receipts from the sale of production attributable to its Royalty Interests. If these payments become too large, the Trust's liquidity and cash available for distribution may be adversely affected.

Under the derivative contracts and separate from the drilling obligation of Chesapeake under the development agreement, there is a requirement that Chesapeake drill and complete a specified number of Development Wells by the end of each six-month period ending June 30 and December 31 during the term of the derivative contracts. In addition, with respect to each such six-month period, the Trust will be required to deliver to the counterparty and the collateral agent under the derivative contracts an independent reserve engineers' report and a report that sets forth certain information regarding the Development Wells drilled and completed as of the end of such six-month period. The obligations to the counterparty under the derivative contracts are secured by the Royalty Interests. Subject to any applicable notice and cure periods, if, among other things, the Trust or Chesapeake is in material default of the drilling, payment or reporting requirements set forth in the derivative contracts, or becomes subject to bankruptcy proceedings or the Trust becomes subject to certain change of control transactions, the counterparty may foreclose on the lien on the Royalty Interests. Following foreclosure by the counterparty, the counterparty may not be able to secure a replacement operator and any amounts recovered in such foreclosure action would not result in any distribution to the Trust unitholders. Even if such foreclosure is solely a result of Chesapeake's action or omission, the Trust may have no remedy against Chesapeake. Such foreclosure would have a material adverse effect on the Trust's results of operations and ability to make distributions.

In addition, the Trust's derivative contracts prohibit the Trust from granting additional liens on any of its properties, other than customary permitted liens and liens in favor of the Trustees of the Trust.

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, NGL and natural gas at that time. There can be no assurance that the prices of oil, NGL and natural gas

Table of Contents

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. 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:

Notwithstanding its drilling obligation to the Trust, Chesapeake's interests may conflict with those of the Trust and the Trust unitholders in situations involving the development, maintenance, operation

Table of Contents

or abandonment of the Underlying Properties. Additionally, 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. Subsequent to fulfilling its drilling obligation, Chesapeake may make decisions with respect to expenditures and decisions to allocate resources on projects in other areas that adversely affect the Underlying Properties, including reducing expenditures on these properties, which could cause oil, NGL and natural gas production to decline at a faster rate and thereby result in lower cash distributions by the Trust in the future.

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 its retained interest in the Underlying Properties, if the Underlying Properties are sold 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.

Following the satisfaction of its drilling obligation to the Trust, 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, Chesapeake 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.

After satisfying its drilling obligation to the Trust, 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, NGL and natural gas 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, after satisfying its drilling obligation, 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, NGL and natural gas 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, including environmental 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 natural gas, oil, brine or well fluids and other

Table of Contents

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 or otherwise negatively impacting the projected economic performance of its prospects. A temporary or permanent halt of the production and sales of oil, NGL and natural gas at any of the Underlying Properties could also reduce Trust distributions by reducing the amount of proceeds available for distribution.

Additionally, 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.

There is also inherent risk of incurring significant environmental costs and liabilities in oil and natural gas operations due to the generation, handling and disposal of materials, including waste petroleum hydrocarbons and other chemicals. Chesapeake may incur joint and several, strict liability under applicable U.S. federal and state environmental laws in connection with releases of petroleum hydrocarbons and other hazardous substances at, on, under or from its leased or owned properties, some of which have been used for oil and natural gas exploration and production activities for a number of years, often by third parties not under its control. Chesapeake also could incur material fines, penalties and government or third-party claims as a result of violations of, or liabilities under, applicable environmental laws and regulations. For non-operated properties, Chesapeake is dependent on the operator for operational and regulatory compliance.

Chesapeake maintains policies of insurance that it believes are customary in the industry, including a \$75 million control of well policy that insures against certain sudden and accidental risks associated with drilling, completing (including hydraulic fracturing) and operating its wells. Chesapeake also carries a \$425 million comprehensive general liability umbrella policy and a \$150 million pollution liability policy. Chesapeake's insurance policies provide for customary deductibles (generally ranging from \$1.0 million to \$5.0 million), and there is no assurance that these policies will provide complete coverage against all operational risks. In addition, these policies do not cover penalties or fines that may be assessed by a governmental authority. If Chesapeake experiences any of the problems described above and its insurance policies do not provide adequate coverage, its ability to conduct operations and perform its obligations to the Trust could be adversely affected. Moreover, these policies also cover properties and operations of Chesapeake unrelated to the Underlying Properties and the Trust. To the extent proceeds from such policies are used to cover losses in Chesapeake's other operations, such coverage may not be available to cover losses relating to the Trust. Finally, Chesapeake is not obligated to the Trust to maintain any particular types or amounts of insurance, and insurance may not be commercially available at the levels indicated above at all times during the life of the Trust. If a well is damaged, Chesapeake would have no obligation to drill a replacement well or otherwise compensate the Trust for the loss. The Trust does not have insurance or indemnification to protect against losses or delays in receiving proceeds from such events.

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

It is customary in the oil and natural gas industry to recover oil and natural gas from deep shale and other formations through the use of horizontal drilling combined with hydraulic fracturing. Hydraulic fracturing is the process of creating or expanding cracks, or fractures, in deep underground formations using water, sand and other additives pumped under high pressure into the formation. Hydraulic fracturing has been used in all Producing Wells and

Development Wells drilled and completed to date, and Chesapeake anticipates that hydraulic fracturing will be used as a means to increase the productivity of each of the remaining Development Wells to be drilled and completed in the future.

The hydraulic fracturing process is typically regulated by state oil and natural gas commissions. Several states, including Pennsylvania, Texas, Colorado, Montana, New Mexico and Wyoming, have adopted, and other states are considering adopting, regulations that could impose more stringent permitting, public disclosure, and well construction requirements on hydraulic fracturing operations. New York has sought to ban fracturing activities altogether. In addition

## Table of Contents

to state laws, some local municipalities have adopted or are considering adopting land use restrictions, such as city ordinances, that may restrict or prohibit the performance of well drilling in general and/or hydraulic fracturing in particular.

Additionally, the EPA has asserted federal regulatory authority over certain hydraulic fracturing activities involving diesel fuel (specifically, when diesel fuel is utilized in the stimulation fluid) under the Safe Drinking Water Act and has published proposed guidance related to this regulatory authority. There are also certain governmental reviews either underway or being proposed that focus on deep shale and other formation completion and production practices, including hydraulic fracturing. Depending on the outcome of these studies, federal and state legislatures and agencies may seek to further regulate such activities. The EPA has issued New Source Performance Standards (NSPS) and National Emissions Standards for Hazardous Air Pollutants (NESHAP) that amend existing NSPS and NESHAP standards for oil and natural gas facilities as well as create new NSPS standards for oil and natural gas production, transmission and distribution facilities. The EPA has also adopted regulations focused on reducing emissions of certain air pollutants by the oil and natural gas industry, including volatile organic compounds, sulfur dioxide, certain air toxics and methane, a greenhouse gas.

Certain environmental and other groups have suggested that additional federal, state and local laws and regulations may be needed to more closely regulate the hydraulic fracturing process. We cannot predict whether additional federal, state or local laws or regulations will be enacted in the future and, if so, what actions any such laws or regulations would require or prohibit. If additional levels of regulation or permitting requirements were imposed through the adoption of new laws and regulations, our business and operations could be subject to delays, increased operating and compliance costs and process prohibitions.

Potential legislative and regulatory actions could increase Chesapeake's costs, reduce its revenue and cash flow from the sales of oil, NGL and natural gas, reduce its liquidity or otherwise alter the way it conducts business.

The activities of exploration and production companies operating in the United States are subject to extensive regulation at the federal, state and local levels. Changes to existing laws and regulations or new laws and regulations such as those described below could, if adopted, have an adverse effect on Chesapeake's business and could reduce cash received by or available for distribution from the Trust.

### Federal Taxation of Independent Producers

Recent federal budget proposals would potentially increase and accelerate the payment of federal income taxes of independent producers of oil and natural gas. Proposals that would significantly affect Chesapeake would repeal the expensing of intangible drilling costs, the percentage depletion allowance and increase the amortization period of geological and geophysical expenses. These changes, if enacted, will make it more costly for Chesapeake to explore for and develop its oil and natural gas resources.

### OTC Derivatives Regulation

In July of 2010, the U.S. Congress enacted the Dodd-Frank Wall Street Reform and Consumer Protection Act (the Dodd-Frank Act), which contains measures aimed at migrating over-the-counter (OTC) derivative markets to exchange-traded and cleared markets while permitting certain "end-users" to continue to use OTC derivatives, and preventing excessive speculation. Chesapeake maintains an active price and basis protection hedging program related to the natural gas and oil it produces to manage the risk of low commodity prices and to predict with greater certainty the cash flow from hedged production. Chesapeake used the OTC market for the fixed price oil swaps contracts that were novated to the Trust. Although the Trust is not permitted to enter into any new derivative contracts and may restructure its existing derivative contracts only in limited circumstances where production falls below hedged

volumes, the Dodd-Frank Act and the rules and regulations promulgated thereunder could significantly increase the cost of restructuring the Trust's existing derivative contracts (including through requirements to post collateral which could adversely affect available liquidity of the Trust), reduce the Trust's ability to monetize or restructure its existing derivative contracts and increase the Trust's exposure to less creditworthy counterparties

#### Climate Change

Various state governments and regional organizations comprising state governments are considering 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

## Table of Contents

findings and issued regulations that require Chesapeake to establish and report an inventory of greenhouse gas emissions and has issued regulations imposing measures to limit greenhouse gas emissions associated with hydraulic fracturing. 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 oil, NGL and natural gas. 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 its 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. Restrictions on emissions of methane or carbon dioxide that may be imposed in various states could adversely affect the oil and natural gas industry. Moreover, incentives to conserve energy or use alternative energy sources could reduce demand for oil, NGL and natural gas.

The Trust is subject to the requirements of the Sarbanes-Oxley Act of 2002, which may impose cost and operating challenges on it.

The Trust is subject to certain of the requirements of the Sarbanes-Oxley Act of 2002 which requires, among other things, maintenance by the Trust of, and reports regarding the effectiveness of, a system of internal control over financial reporting. Complying with these requirements may pose operational challenges and may cause the Trust to incur unanticipated expenses. Any failure by the Trust to comply with these requirements could lead to a loss of public confidence in the Trust's internal controls and in the accuracy of the Trust's publicly reported results.

### 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 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. Therefore, treatment of the Trust as a corporation would result in 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

Table of Contents

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.

In taxable years beginning after December 31, 2012, 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. Net investment income appears to include interest income and royalty income derived from investments such as the Trust units as well as any net gain from the disposition of Trust units. In addition, beginning January 1, 2013, 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, NGL and natural gas attributable to the Trust will be approximately 2.0% for the first four years of production for each well, and approximately 7.0% thereafter. Moreover, these rates are subject to change by new legislation at any time.

Current law may change so as to cause the Trust to be treated as a corporation for U.S. federal income tax purposes or otherwise subject the Trust to entity-level taxation. Specifically, 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 interpretation at any time. For example, from time to time, legislation is proposed that would affect partnership tax treatment for certain publicly traded partnerships. Any modification to the federal income tax laws and interpretations thereof may or may not be applied retroactively. The Trust is unable to predict whether any of these changes or any other proposals will ultimately be enacted. Any such legislation would likely also affect the Trust tax treatment for state tax purposes.

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 and income, gain, loss and deduction may be reallocated among Trust unitholders.

The Trust has not requested a ruling from the IRS with respect to its treatment as a partnership for U.S. federal income tax purposes or any other matter affecting the Trust. The IRS may adopt positions that differ from the positions the Trust takes. It may be necessary to resort to administrative or court proceedings to attempt to sustain some or all of the positions the Trust takes. A court may not agree with some or all of the positions the Trust takes. Any contest with the IRS may materially and adversely impact the market for the Trust units and the price at which they trade. In addition, the Trust's costs of any contest with the IRS will be borne indirectly by the Trust unitholders because the costs will reduce the Trust's cash available for distribution.

Trust unitholders will be required to pay taxes on their share of the Trust's income even if they do not receive any cash distributions from the Trust.

Because the Trust unitholders will be treated as partners to whom the Trust will allocate taxable income that could be different in amount than the cash the Trust distributes, Trust unitholders will be required to pay any federal income taxes and, in some cases, state and local income taxes on their share of the Trust's taxable income even if they receive no cash distributions from the Trust. Trust unitholders may not receive cash distributions from the Trust equal to their share of the Trust's taxable income or even equal to the actual tax liability that results from that income.

Tax gain or loss on the disposition of the Trust units could be more or less than expected.

Trust unitholders that sell their Trust units will recognize a gain or loss equal to the difference between the amount realized and the tax basis in those Trust units. Because distributions in excess of the Trust unitholders allocable share of the Trust's net taxable income decrease the tax basis in such Trust unitholders' Trust units, the amount, if any, of such prior excess distributions with respect to the Trust units sold will, in effect, become taxable income if Trust units are sold at a price greater than the tax basis in those Trust units, even if the price received is less than the original cost of the Trust units. Furthermore, a substantial portion of the amount realized, whether or not representing gain, may be taxed as ordinary income due to potential recapture items, including depletion recapture.

Table of Contents

The ownership and disposition of Trust units by non-U.S. persons may result in adverse tax consequences to them.

Investment in Trust units by non-U.S. persons raises issues unique to them. For example, distributions to non-U.S. persons will be reduced by withholding taxes at the highest applicable effective tax rate, and non-U.S. persons may be required to file U.S. federal income tax returns and pay tax on their share of the Trust's taxable income or proceeds from the sale of Trust units.

The Trust will treat each purchaser of Trust units as having the same economic attributes without regard to the actual Trust units purchased. The IRS may challenge this treatment, which could adversely affect the value of the Trust units.

Due to a number of factors, including the Trust's inability to match transferors and transferees of Trust units, the Trust will adopt positions that may not conform to all aspects of existing Treasury Regulations. A successful IRS challenge to those positions could adversely alter the tax effects of an investment in Trust units. It also could affect the timing of these tax benefits or the amount of gain from the sale of Trust units by Trust unitholders and could have a negative impact on the value of the Trust units or result in audit adjustments to Trust unitholders tax returns.

The Trust will prorate its items of income, gain, loss and deduction between transferors and transferees of the Trust units each quarter based upon the record ownership of the Trust units on the quarterly record date in such quarter, instead of on the basis of the date a particular Trust unit is transferred. The IRS may challenge this treatment, which could change the allocation of items of income, gain, loss and deduction among the Trust unitholders.

The Trust will generally prorate its items of income, gain, loss and deduction between transferors and transferees of the Trust units based upon the record ownership of the Trust units on the quarterly record date in such quarter instead of on the basis of the date a particular Trust unit is transferred.

The use of this proration method may not be permitted under existing Treasury Regulations, and, although the United States Treasury Department issued proposed Treasury Regulations allowing a similar monthly simplifying convention, such regulations are not final and do not specifically authorize the use of the proration method the Trust has adopted. If the IRS were to challenge the Trust's proration method, the Trust may be required to change its allocation of items of income, gain, loss and deduction among the Trust unitholders and the costs to the Trust of implementing and reporting under any such changed method may be significant.

A Trust unitholder whose Trust units are loaned to a "short seller" to cover a short sale of Trust units may be considered as having disposed of those Trust units. If so, he would no longer be treated for tax purposes as a partner with respect to those Trust units during the period of the loan and may recognize gain or loss from the disposition.

Because a Trust unitholder whose Trust units are loaned to a "short seller" to cover a short sale of Trust units may be considered as having disposed of the loaned Trust units, he may no longer be treated for tax purposes as a partner with respect to those Trust units during the period of the loan to the short seller and the unitholder may recognize gain or loss from such disposition. Moreover, during the period of the loan to the short seller, any of the Trust's income, gain, loss or deduction with respect to those Trust units may not be reportable by the unitholder and any cash distributions received by the unitholder as to those Trust units could be fully taxable as ordinary income. The Trust's counsel has not rendered an opinion regarding the treatment of a unitholder where Trust units are loaned to a short seller to cover a short sale of Trust units; therefore, Trust unitholders desiring to assure their status as partners and avoid the risk of gain recognition from a loan to a short seller are urged to modify any applicable brokerage account agreements to prohibit their brokers from loaning their Trust units.

The Trust will adopt certain valuation methodologies that may affect the income, gain, loss and deduction allocable to the Trust unitholders. The IRS may challenge this treatment, which could adversely affect the value of the Trust units.

The U.S. federal income tax consequences of the ownership and disposition of Trust units will depend in part on the Trust's estimates of the relative fair market values, and the initial tax bases of the Trust's assets. Although the Trust may from time to time consult with professional appraisers regarding valuation matters, the Trust will make many of

41

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Table of Contents

the relative fair market value estimates itself. These estimates and determinations of basis are subject to challenge and will not be binding on the IRS or the courts. If the estimates of fair market value or basis are later found to be incorrect, the character and amount of items of income, gain, loss or deductions previously reported by Trust unitholders might change, and Trust unitholders might be required to adjust their tax liability for prior years and incur interest and penalties with respect to those adjustments.

The sale or exchange of 50% or more of the Trust's capital and profits interests during any twelve-month period will result in the technical termination of the Trust for U.S. federal income tax purposes.

The Trust will be considered to have technically terminated for U.S. federal income tax purposes if there is a sale or exchange of 50% or more of the total interests in its capital and profits within a twelve-month period. For purposes of determining whether the 50% threshold has been met, multiple sales of the same Trust unit within any 12 month period will be counted only once. The Trust's termination would, among other things, result in the closing of its taxable year for all Trust unitholders, which would result in the Trust filing two tax returns (and the Trust unitholders could receive two Schedules K-1 if relief is not available) for one calendar year. The IRS has announced a relief procedure whereby if a publicly traded partnership that has technically terminated requests and the IRS grants special relief, among other things, the partnership will be required to provide only a single Schedule K-1 to unitholders for the tax year in which the termination occurs. In the case of a unitholder reporting on a taxable year other than a calendar year ending December 31, the closing of the Trust's taxable year may also result in more than 12 months of the Trust's taxable income being includable in his taxable income for the year of termination. A technical termination would not affect the Trust's classification as a partnership for U.S. federal income tax purposes, but instead, the Trust would be treated as a new partnership for tax purposes. If treated as a new partnership, the Trust must make new tax elections and could be subject to penalties if the Trust is unable to determine that a technical termination occurred.

Trust unitholders may be subject to state and local taxes and return filing requirements in jurisdictions where they do not live as a result of investing in Trust units.

In addition to federal income taxes, Trust unitholders will likely be subject to other taxes, including Oklahoma state income taxes, even if they do not live in Oklahoma. Trust unitholders will likely be required to file Oklahoma state income tax returns and pay Oklahoma state income tax. Further, Trust unitholders may be subject to penalties for failure to comply with those requirements. It is each Trust unitholder's responsibility to file all U.S. federal, state, local and non-U.S. tax returns.

Certain U.S. federal income tax preferences currently available with respect to oil, NGL and natural gas production may be eliminated as a result of future legislation.

Among the proposed changes contained in President Obama's Budget Proposal for Fiscal Year 2013 is the elimination of certain key U.S. federal income tax preferences relating to oil, NGL and natural gas exploration and production. The President's budget proposes to eliminate certain tax preferences applicable to taxpayers engaged in the exploration or production of natural resources. Specifically, the budget proposes to repeal the deduction for percentage depletion with respect to wells, including interests such as the Perpetual Royalties, in which case only cost depletion would be available.

ITEM 1B. Unresolved Staff Comments

None.

ITEM 2. Properties

Reference is made to "Item 1 - Business," which is incorporate herein by reference.

ITEM 3. Legal Proceedings

There are no legal proceedings to which the Trust is a party.

Chesapeake has advised the Trustee that Chesapeake is involved in various lawsuits and disputes incidental to its business operations, including commercial disputes, personal injury claims, claims for underpayment of royalties, property damage claims and contract actions. With regard to the latter, various mineral or leasehold owners have filed lawsuits against Chesapeake seeking specific performance to require Chesapeake to acquire their oil and natural gas interests and pay acreage bonus payments, damages based on breach of contract and/or, in certain cases, punitive damages based on alleged fraud. Chesapeake has advised the Trustee that Chesapeake has successfully defended a number of these cases in various courts, has settled others and believes that it has substantial defenses to the claims made in those pending at the trial court and on appeal.

Chesapeake has advised the Trustee that at this time Chesapeake has six lawsuits in process that involve properties in the AMI and have claims that exceed \$100,000 individually or in aggregate. The Trust is a not a party to any such lawsuit and Chesapeake has advised the Trustee that Chesapeake is not aware of any pending or threatened lawsuit or dispute that, individually or in the aggregate, is likely to have a material adverse effect on the Trust's financial position or distributable income.

ITEM 4. Mine Safety Disclosures

Not applicable.

Table of Contents

## PART II

## ITEM 5. Market for Units of the Trust, Related Unitholder Matters and Trust Purchases of Units

## Common Units Representing Beneficial Interests

The common units representing beneficial interests in the Trust are listed and commenced trading on the New York Stock Exchange on November 11, 2011 under the symbol "CHKR". The following table sets forth, for the periods indicated, the high and low sales prices per common unit as reported by the New York Stock Exchange:

	Common Units	
	High	Low
Fourth Quarter 2011 (November 16 through December 31)	\$24.25	\$18.48
First Quarter 2012 (January 1 through March 31)	\$30.24	\$20.78
Second Quarter 2012 (April 1 through June 30)	\$26.88	\$17.37
Third Quarter 2012 (July 1 through September 30)	\$23.47	\$19.60
Fourth Quarter 2012 (October 1 through December 31)	\$21.41	\$16.23

As of December 31, 2012, 35,062,500 common units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding and held by nine unitholders of record. Such units were issued on November 16, 2011. The following table sets forth, for the periods indicated, the common and subordinated distribution per unit.

	Distribution per Unit	
	Common Unit	Subordinated Unit
Fourth Quarter 2011	\$0.5800	\$0.5800
First Quarter 2012	\$0.7277	\$0.7277
Second Quarter 2012	\$0.6588	\$0.6588
Third Quarter 2012	\$0.6100	\$0.4819
Fourth Quarter 2012	\$0.6300	\$0.2208

Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan 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 current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans 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. As of December 31, 2011, a \$200,000 non-interest bearing loan was outstanding with Chesapeake and the loan was repaid in February 2012. The repayment amount was included as Trust administrative expenses in the determination of the distribution amount.

## Equity Compensation Plans

The Trust does not have any employees and, therefore, does not maintain any equity compensation plans, nor has it purchased or issued any additional units during the 2012 calendar year covered by this Annual Report.

## Recent Sales of Unregistered Securities

On November 16, 2011, in connection with the initial public offering by the Trust of its common units, Chesapeake Exploration conveyed the PDP Royalty Interest and the Development Royalty Interest to the Trust in exchange for 12,062,500 common units, 11,687,500 subordinated units and \$409.7 million in cash.

Purchases of Equity Securities

None.

44

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Table of Contents

## ITEM 6. Selected Financial Data

## Distributable Income

The following is a summary of royalty income, interest income and distributable income for the years ended December 31, 2012 and 2011 (in thousands except per unit amounts):

	2012	2011
Royalty Income	\$127,335	\$29,334
Interest Income	\$3	\$2
Distributable income	\$116,510	\$27,115
Distributable income per common unit	\$2.6265	\$0.5800
Distributable income per subordinated unit	\$2.0892	\$0.5800

## Assets, Liabilities and Trust Corpus

The following is the balance of total assets, total liabilities and trust corpus on December 31, 2012 and December 31, 2011 (in thousands except per unit amounts):

	2012	2011
Total Assets	\$429,621	\$483,659
Total Liabilities	\$8,084	\$20,741
Trust Corpus	\$421,537	\$462,918

## ITEM 7. Trustee's Discussion and Analysis of Financial Condition and Results of Operations

## Introduction

The following discussion and analysis is intended to help the reader understand the Trust's financial condition and results of operations. This discussion and analysis should be read in conjunction with the audited financial statements and the accompanying notes relating to the Trust and the Underlying Properties included in Part II, Item 8 of this Annual Report and the Discussion and Analysis of Results from the Producing Wells included in Part I, Item 2 of this Annual Report. Capitalized items in this Item 7 have the same meanings ascribed to them in Note 1 to the Trust's financial statements included in Part II, Item 8 of this Annual Report.

## Overview

The Trust is a statutory trust formed in June 2011 under the Delaware Statutory Trust Act. The business and affairs of the Trust are managed by the Trustee and, as necessary, the Delaware Trustee. The Trust does not conduct any operations or activities other than owning the Royalty Interests and activities related to such ownership. The Trust's purpose is generally to own the Royalty Interests, to distribute to the Trust unitholders cash that the Trust receives in respect of the Royalty Interests and the derivative contracts (described in Note 3 to the financial statements contained in Part II, Item 8 of this Annual Report and to perform certain administrative functions in respect of the Royalty Interests and the Trust units. The Trust derives all or substantially all of its income and cash flow from the Royalty Interests and the derivative contracts. The Trust is treated as a partnership for federal income tax purposes. During November 2011, the Trust completed an initial public offering of its common units representing beneficial interests in the Trust, the net proceeds of which were remitted to Chesapeake as partial consideration for its conveyance of the Royalty Interests to the Trust.

Concurrent with the initial public offering, Chesapeake conveyed the Royalty Interests to the Trust effective July 1, 2011, which included interests in the Producing Wells and the Development Wells. Chesapeake is obligated to drill

and complete, cause to be drilled and completed or participate as a non-operator in the drilling of the Development Wells from drill sites in the AMI on or prior to June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into

## Table of Contents

production or plug and abandon each Development Well. As of December 31, 2012, Chesapeake had drilled and completed 51 wells within the AMI (approximately 55.1 Development Wells as calculated under the development agreement). As of March 8, 2013, Chesapeake had drilled and completed, or caused to be drilled and completed, a total of 56 wells within the AMI (approximately 61.3 Development Wells as calculated under the development agreement).

The Trust is not responsible for any costs related to the drilling of the Development Wells or any other operating or capital costs of the Underlying Properties, and Chesapeake is not permitted to drill and complete any well in the Colony Granite Wash formation on acreage included within the AMI for its own account until it has satisfied its drilling obligation to the Trust.

The Royalty Interests entitle the Trust to receive 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sales of production of oil, NGL and natural gas attributable to Chesapeake's net revenue interest in the Producing Wells and 50% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sales of oil, NGL and natural gas production attributable to Chesapeake's net revenue interest in the Development Wells. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, NGL and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by Chesapeake or its affiliates.

On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering a portion of the oil and NGL production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015. The Trust's distributable income will include net settlements under these derivative contracts. The value of the derivative contracts as of December 31, 2012 was a net liability of \$8.1 million.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. The distribution made in the fourth quarter of 2012, consisting of proceeds attributable to production from June 1, 2012 through August 31, 2012, was made on November 29, 2012 to record unitholders as of November 19, 2012.

The amount of Trust revenues and cash distributions to Trust unitholders will fluctuate from quarter to quarter depending on several factors, including:

- timing of sales from the Development Wells;
- oil, NGL and natural gas prices received;
- volumes of oil, NGL and natural gas produced and sold;
- amounts received from, or paid under, derivative contracts;
- certain post-production expenses and any applicable taxes; and
- the Trust's expenses.

## Results of Trust Operations

The quarterly payments to the Trust with respect to the Royalty Interests are based on the amount of proceeds actually received by Chesapeake during the preceding calendar quarter. Proceeds from production are typically received by Chesapeake one month after production. Due to the timing of the payment of production proceeds, quarterly distributions made by Chesapeake to the Trust will generally include royalties attributable to sales of oil, NGL and natural gas for three months, comprised of the first two months of the quarter just ended and the last month of the quarter prior to that one. Chesapeake is required to make the Royalty Interest payments to the Trust within 35 days of the end of each calendar quarter. As a result, the cash received by the Trust with respect to the Royalty Interests during the year ended December 31, 2012 substantially represented royalties attributable to proceeds from sales of oil, NGL and natural gas for September 1, 2011 through August 31, 2012. The cash received by the Trust with respect to the Royalty Interests during the six months ended December 31, 2011 substantially represented the royalties

attributable to proceeds from sales of oil, NGL and natural gas for July 1, 2011 through August 31, 2011.

Recently, low natural gas prices combined with stronger oil prices have resulted in increased drilling activity in oil- and NGL-rich plays as operators have reduced uneconomic natural gas drilling activities. The resulting increase

Table of Contents

in production volumes of NGL led to a significant decrease in the price of NGL in both absolute terms and on a relative basis compared to oil. The Trust's exposure to low prices for NGL and natural gas production volumes have resulted in per unit income available for distribution below the subordination threshold. Accordingly, on August 30, 2012, the Trust paid a distribution at the subordination threshold of \$0.6100 per common unit for the three month production period ended May 31, 2012 and a subordinated unit distribution of \$0.4819 per subordinated unit for such period. On November 19, 2012, the Trust paid a common unit distribution at the subordination threshold of \$0.6300 per common unit for the three month production period ended August 31, 2012 and a subordinated unit distribution of \$0.2208 per subordinated unit for such period. Additionally, on March 1, 2013 the Trust paid a common unit distribution at the subordination threshold of \$0.6700 per common unit for the three-month production period ended November 30, 2012, and a subordinated unit distribution of \$0.3772 per subordinated unit for such period.

Sustained low commodity prices will reduce the Trust's revenues and distributable income available to unitholders, and may result in future distributions to common unitholders at or below the subordination threshold.

Trust Operations for the Year Ended December 31, 2012 as compared to Inception to December 31, 2011.

The Trust's distributable income was \$116.5 million for the year ended December 31, 2012 compared to \$27.1 million for the period from inception (the effective date of the conveyance of the Royalty Interests to the Trust was July 1, 2011 and the Trust has received the proceeds of production attributable to the Royalty Interests from that date) through December 31, 2011, an increase of \$89.4 million. This increase was primarily due to the increase in the net proceeds to the Trust, which was a result of a full twelve months of activity in 2012 compared to two month of activity in 2011 in the year-over-year comparison.

On a per unit basis, cash distributions during the year ended December 31, 2012 were \$2.6265 per common unit and \$2.0892 per subordinated unit covering production for the period from September 1, 2011 to August 31, 2012 as compared to \$0.58 per common and subordinated units for the six months ended December 31, 2011 covering production from July 1, 2011 to August 31, 2011. Distributable income for the year ended December 31, 2012, attributable to production from September 1, 2011 to August 31, 2012, and for the six months ended December 31, 2011, attributable to production from July 1, 2011 to August 31, 2011, was calculated as follows (in thousands except for unit and per unit amounts):

	Year Ended December 31, 2012	Six Months Ended December 31, 2011
Revenues:		
Royalty income <sup>(1)</sup>	\$127,335	\$29,334
Interest income	3	2
Total Revenues	\$127,338	\$29,336
Expenses:		
Production taxes	2,707	906
Trust administrative expenses <sup>(2)</sup>	1,732	1,315
Derivative settlement loss	6,389	—
Total Expenses	10,828	2,221
Distributable income available to unitholders	\$116,510	\$27,115
Distributable income per common unit (35,062,500 units issued and outstanding)	\$2.6265	\$0.5800
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	\$2.0892	\$0.5800

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

Royalty Income. Royalty income to the Trust for the year ended December 31, 2012 and attributable to production from September 1, 2011 to August 31, 2012 totaled \$127.3 million, representing an increase of \$98.0 million over the prior year's royalty income of \$29.3 million attributable to production from July 1, 2011 to August 31, 2011. This increase was primarily due to a full twelve months of production paid to unitholders in 2012 compared to two months of production in 2011. This increase was partially offset by price decreases for NGL and natural gas production. The average price

Table of Contents

received for NGL production of \$35.01 per boe in 2012 was \$11.64 lower than the average price of \$46.65 per boe in 2011. In addition, prices received for natural gas production averaged \$1.84 per mcf in 2012, \$1.42 lower than the average price of \$3.26 per mcf in 2011. The average prices received for oil production were \$91.65 per barrel and \$88.26 per barrel for 2012 and 2011, respectively. Although the average price received for oil production was \$3.39 higher in 2012 than in 2011, this price increase was partially offset by payments to the counterparty pursuant to the Trust's oil derivative contracts.

Sales of production attributable to the Royalty Interests for the year ended December 31, 2012 were 673 mbbls of oil, 1,234 mbbls of NGL and 12,179 mmcf of natural gas as compared to production of 133 mbbls of oil, 225 mbbls of NGL and 2,172 mmcf of natural gas attributable to the Royalty Interests for the six months ended December 31, 2011. Total production attributable to the Royalty Interests for the year ended December 31, 2012 was 3,937 mboe as compared to 720 mboe for the six months ended December 31, 2011, an increase of 3,217 mboe. This increase was primarily due to the increase in the net proceeds to the Trust, which was a result of a full twelve months of activity in 2012 compared to two month of activity in 2011 as well as Chesapeake's completion of 43.6 Development Wells (as calculated under the development agreement) during 2012.

Average sales prices are net of certain post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses and exclude production taxes. Production Taxes. Production taxes are calculated as a percentage of oil, NGL and natural gas revenues, net of any applicable tax credits. Production taxes for the year ended December 31, 2012 totaled \$2.7 million, or \$0.69 per boe, or approximately 2.1% of royalty income, as compared to production taxes of \$0.9 million, or \$1.26 per boe, or approximately 3.1% of royalty income. This decrease in production tax per boe is due to an increase in the number of wells taxed at an incentive tax rate due to horizontal well qualification.

Trust Administrative Expenses. Trust administrative expenses for the year ended December 31, 2012 totaled \$1.7 million as compared to \$1.3 million for the six months ended December 31, 2011. The increase was primarily the result of a full year of expenses in 2012 compared to six months in 2011. The increase was partially offset by the \$1.0 million initial cash reserve for Trust administrative expenses established in 2011. Trust administrative expenses primarily consist of the administrative fees paid to the Trustees and Chesapeake and costs for accounting and legal services.

Derivative Settlement Loss. The Trust records gains or losses from the derivative contracts when proceeds are received or payments are made, respectively. Swaps covering October 2011 through August 2012 production were settled, during the year ended December 31, 2012, with proceeds from royalty income for the same period. Total losses during the period were \$6.4 million, or \$0.14 per unit. The Trust had no settlement of swaps during the six months ended December 31, 2011.

Distributable Income. Distributable income paid to the Trust unitholders during the year ended December 31, 2012 and attributable to production from September 1, 2011 to August 31, 2012 was \$116.5 million, or \$2.6265 per common unit and \$2.0892 per subordinated unit, which included a \$1.6 million reduction for Trust administrative expenses and a cash reserve for the payment of future Trust administrative expenses. Distributable income paid to the Trust unitholders during the six months ended December 31, 2011 and attributable to production from July 1, 2011 to August 31, 2011 was \$27.1 million, or \$0.5800 per common unit and subordinated unit, which included a \$1.3 million reduction for Trust administrative expenses and a cash reserve for the payment of future Trust administrative expenses. Administrative expenses for a full year 2012 were only \$0.3 million higher than the two month period in 2011 primarily due to the \$1.0 million initial cash reserve. See Royalty Income above for discussions of price and production changes.

Development Wells. As of December 31, 2012, all of the Producing Wells were producing and approximately 55.1 Development Wells (as calculated under the development agreement) were completed and producing. The amount that could be recovered under the Drilling Support Lien as of December 31, 2012 was approximately \$140.1 million. In addition, 3.0 Development Wells (as calculated under the development agreement) were drilled in the AMI and subsequently completed in January 2013. As of March 8, 2013, Chesapeake had drilled and completed, or caused to

be drilled and completed, a total of 56 wells within the AMI (approximately 61.3 Development Wells as calculated under the development agreement) and the amount that could be recovered under the Drilling Support Lien was approximately \$126.3 million.

48

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Table of Contents

## Liquidity and Capital Resources

The Trust's principal sources of liquidity and capital are cash flows generated from the Royalty Interests, the loan commitment as described below and, during periods in which oil prices fall below the fixed price received on derivative contracts, the derivative contracts. The Trust's primary uses of cash are distributions to Trust unitholders, including, if applicable, incentive distributions to Chesapeake, payments of production taxes, payments of Trust administrative expenses, including any reserves established by the Trustee for future liabilities and repayment of loans, payments for derivative contract settlements and payments of expense reimbursements to Chesapeake for out-of-pocket expenses it incurs on behalf of the Trust. Administrative expenses include payments to the Trustee and the Delaware Trustee as well as a quarterly fee of \$50,000 to Chesapeake pursuant to an administrative services agreement. Each quarter, the Trustee determines the amount of funds available for distribution. Available funds are the excess cash, if any, received by the Trust from the sales of oil, NGL and natural gas production attributable to the Royalty Interests during the quarter, over the Trust's expenses for the quarter and any cash reserve for the payment of liabilities of the Trust, subject in all cases to the subordination and incentive provisions described previously. The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each calendar quarter through, and including, the quarter ending June 30, 2031.

The following is a summary of distributable income by quarter for the year ended December 31, 2012 and and six months ended December 31, 2011 (in thousands except per unit amounts):

2012	Q1	Q2	Q3	Q4	TOTAL
Distributable income	\$34,019	\$30,801	\$27,020	\$24,670	\$116,510
Distributable income per common unit	\$0.7277	\$0.6588	\$0.6100	\$0.6300	\$2.6265
Distributable income per subordinated unit	\$0.7277	\$0.6588	\$0.4819	\$0.2208	\$2.0892
2011	Q1	Q2	Q3	Q4	TOTAL
Distributable income	—	—	—	\$27,115	\$27,115
Distributable income per common unit	—	—	—	\$0.5800	\$0.5800
Distributable income per subordinated unit	—	—	—	\$0.5800	\$0.5800

On February 8, 2013, the Trust declared a cash distribution of \$0.6700 per common unit and \$0.3772 per subordinated unit, consisting of proceeds attributable to production from September 1, 2012 to November 30, 2012, to record unitholders as of February 19, 2013. The distribution was paid on March 1, 2013. The Trust's quarterly income available for distribution was \$0.5968 per unit, which was \$0.0732 below the subordination threshold. As a result, the distribution per common unit was equal to the subordination threshold of \$0.6700 for the quarter.

The Trustee can authorize the Trust to borrow money to pay Trust expenses that exceed cash held by the Trust. The Trustee may authorize the Trust to borrow from the Trustee as a lender provided the terms of the loan are fair to the Trust unitholders. The Trustee may also deposit funds awaiting distribution in an account with itself, if the interest paid to the Trust at least equals amounts paid by the Trustee on similar deposits, and make other short-term investments with the funds distributed to the Trust. The Trustee may also hold funds awaiting distribution in a non-interest bearing account.

Pursuant to the Trust Agreement, if at any time the Trust's cash on hand (including cash reserves) is not sufficient to pay the Trust's ordinary course expenses as they become due, Chesapeake will loan 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 current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans 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.

The Trust is not responsible for any costs related to the drilling of the Development Wells and 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

Table of Contents

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. As Chesapeake fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned are released from the Drilling Support Lien and the total dollar amount that may be recovered by the Trust for Chesapeake's failure to fulfill its drilling obligation is proportionately reduced.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements. The Trust has not guaranteed the debt of any other party, nor does the Trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations other than the derivative contracts disclosed in the section "Quantitative and Qualitative Disclosures About Market Risk" in Item 7A of this Annual Report.

Contractual Obligations

As of December 31, 2012, the Trust had no obligations or commitments to make future contractual payments other than the Trustee administrative fee, administrative services fee, the collateral agent fee and the Delaware Trustee administrative fee payable to the Trustee, Chesapeake and Wells Fargo Bank, N.A., as collateral agent under the derivative contracts and the Delaware Trustee, respectively.

Contractual Obligations (\$ in thousands):	Total	Less than 1 Year	1-3 Years	3-5 Years	More than 5 Years
Trustee administrative fee	\$3,238	\$175	\$350	\$350	\$2,363
Chesapeake administrative services fee	3,700	200	400	400	2,700
Wells Fargo collateral agent fee <sup>(1)</sup>	68	23	45	—	—
Delaware Trustee administrative fee	37	2	4	4	27
Total contractual obligations	\$7,043	\$400	\$799	\$754	\$5,090

(1) Collateral agent fee extends only through September 30, 2015.

The Trust is obligated to make quarterly cash distribution of substantially all of its cash receipts, after deducting the Trust's expenses, approximately 60 days following the completion of each calendar quarter through, and including, the quarter ending June 30, 2031.

Critical Accounting Policies and Estimates

**Basis of Accounting.** Financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") as the Trust records revenues when received and expenses when paid and may also establish certain cash reserves for contingencies that would not be accrued in financial statements prepared in accordance with GAAP. This non-GAAP, comprehensive basis of accounting corresponds to the accounting principles permitted for royalty trusts by the Securities and Exchange Commission ("SEC") as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts. The accompanying financial statements as of December 31, 2012 and 2011 have been prepared by the Trust in accordance with the accounting policies noted below.

**Investment in Royalty Interests.** The conveyance of the Royalty Interests to the Trust is accounted for as a transfer of properties between entities under common control and recorded at the historical cost of Chesapeake ("Investment in Royalty Interests"), which is based on an allocation of the historical net book value of Chesapeake's full cost pool according to the fair value of the Royalty Interests relative to the fair value of Chesapeake's proved reserves. The carrying value of the Trust's Investment in Royalty Interests will not necessarily be indicative of the fair value of such Royalty Interests.

This investment is amortized as a single cost center on a units-of-production basis over total proved reserves. Such amortization does not reduce distributable income, rather it is charged directly to the Trust corpus. Revisions to

estimated future units-of-production are treated on a prospective basis beginning on the date significant revisions are known.

50

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Table of Contents

On a quarterly basis, the Trust evaluates the carrying value of the Investment in Royalty Interests under the full cost accounting method prescribed by the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, the carrying value of the Investment in Royalty Interests may not exceed an amount equal to the PV-10 for the Trust's proved reserves. Any write-downs resulting from the ceiling test will be non-cash charges to the Trust corpus and will not affect distributable income.

Use of Estimates. The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets, liabilities and Trust corpus during the reporting period. Significant estimates that impact the Trust's financial statements include estimates of proved oil, NGL and natural gas reserves, which are used to compute the Trust's amortization of Investment in Royalty Interests and, as necessary, to evaluate potential impairment of Investment in Royalty Interests. Actual results could differ from those estimates.

Derivatives. To mitigate a portion of the exposure to adverse market changes of oil and NGL prices, the Trust is party to derivative contracts with its derivative counterparty. See Note 3 to the financial statements contained in Part II, Item 8 of this Annual Report for further discussion of the derivative contracts currently outstanding.

The Trust records gains or losses from the derivative contracts conveyed under the derivative contracts when proceeds are received or payments are made, respectively. Additionally, changes in the fair value of the derivative contracts are accounted for as an adjustment to Trust corpus and the fair value carried on the Statement of Assets and Trust Corpus. Because the initial derivative contracts do not cover production periods prior to October 1, 2011, there were no proceeds received or payments made related to derivative settlements prior to October 1, 2011.

Revenues and Expenses. Revenues received by the Trust are net of existing royalties and overriding royalties associated with Chesapeake's interests and are reduced by certain post-production expenses, production taxes and other allowable expenses, such as the Trust's administrative expenses, in order to determine distributable income. The Royalty Interests are not burdened by field and lease operating expenses.

ITEM 7A. Quantitative and Qualitative Disclosures about Market Risk

The discussion in this section provides information about derivative contracts between the Trust and its counterparty effective October 1, 2011. The derivative contracts cover a portion of the expected production attributable to the Royalty Interests from the Producing Wells and the Development Wells through September 30, 2015. The derivative contracts are settled in cash and do not require the actual delivery of oil or NGL at settlement. The contracts are settled based upon NYMEX prices. Under the derivative contracts, the Trust receives payments directly from its counterparty and is required to pay any amounts owed to its counterparty. The Trust does not have the ability to enter into any additional oil, NGL or natural gas derivative contracts, except in limited circumstances involving the restructuring of the existing oil derivatives contracts.

Table of Contents

As of December 31, 2012, the Trust had the following oil derivative contracts:

Production Quarter	Fixed-Price Oil Swaps		
	Volume (mdbl)	Weighted Avg. Price (per bbl)	Fair Value (\$ in thousands)
Q3 2012 <sup>(1)</sup>	60.9	86.83	(201 )
Q4 2012 <sup>(2)</sup>	185.5	86.98	(467 )
Q1 2013	182.2	87.37	(780 )
Q2 2013	184.3	87.60	(1,061 )
Q3 2013	187.9	87.79	(1,098 )
Q4 2013	184.2	87.99	(979 )
Q1 2014	179.8	88.08	(844 )
Q2 2014	180.3	88.21	(735 )
Q3 2014	178.8	88.34	(633 )
Q4 2014	174.3	88.45	(524 )
Q1 2015	171.0	88.59	(380 )
Q2 2015	175.4	88.76	(247 )
Q3 2015	153.6	88.90	(135 )
Total	2,198.2	\$88.03	\$(8,084 )

(1) Includes September 2012 production that was settled in February 2013.

(2) Includes October and November 2012 production that was settled in February 2013.

To the extent oil production falls below the hedged oil volume, the derivative contracts will also cover NGL production. Such estimated production of NGL is hedged with oil contracts using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. In 2012, NGL prices have decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the derivative contracts will not effectively mitigate the price risk of the Trust's NGL production.

The obligations to the counterparty under the derivative contracts are secured by the Royalty Interests. The value of the derivative contracts as of December 31, 2012 was a net liability of \$8.1 million.

**Oil, NGL and Natural Gas Price Risk.** The Trust's primary asset and source of income is the Royalty Interests, which generally entitle the Trust to receive a portion of the net proceeds from the sales of oil, NGL and natural gas from the Underlying Properties. The Trust is significantly exposed to fluctuations in the prices received for oil, NGL and natural gas produced and sold. The derivative contracts described above are designed to mitigate a portion of the variability of the prices received for the Trust's share of production. The use of crude oil derivative contracts to partially mitigate the price risk of NGL production, to the extent oil production falls below the hedged oil volume, is subject to basis risk to the extent oil and NGL prices are not highly correlated.

**Credit Risk.** A portion of the Trust's liquidity is concentrated in the derivative contracts described above. The use of oil derivative contracts exposes the Trust to credit risk from its counterparty, which has an investment grade credit rating.

**Credit Risk Associated With Chesapeake.** Chesapeake's ability to perform its obligations to the Trust will depend on its future financial condition, economic performance, access to capital, ability to sell assets and ability to comply with the financial covenants contained in its debt instruments, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on the Drilling Support Lien to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI,

file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the Trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation and the maximum amount the Trust can recover in a foreclosure or other action was limited to approximately \$126.3 million as of March 8, 2013 and will decrease as the remaining Development Wells are drilled and completed.

Table of Contents

Delays and expenses associated with a foreclosure could reduce distributions to the Trust unitholders by reducing the amount of proceeds available for distribution and may result in the loss of acreage due to leasehold expirations. Any amounts actually recovered in a foreclosure action would be applied to completion of Chesapeake's drilling obligation, would not result in any distribution to the Trust unitholders and may be insufficient to drill the number of wells needed for the Trust to realize the full value of the Royalty Interests in the Development Wells.

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 could also be unable to provide support to the Trust through loans and performance of its management duties.

Table of Contents

ITEM 8. Financial Statements and Supplementary Data

REPORT OF INDEPENDENT REGISTERED PUBLIC ACCOUNTING FIRM

To the Unitholders of Chesapeake Granite Wash Trust and The Bank of New York Mellon Trust Company, N.A,  
Trustee:

We have audited the accompanying statements of assets, liabilities and trust corpus of Chesapeake Granite Wash Trust (the "Trust") as of December 31, 2012 and 2011, and the related statements of distributable income and of changes in trust corpus for the year ended December 31, 2012 and the six month period ended December 31, 2011. We also have audited the Trust's internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Trustee is responsible for these financial statements, for maintaining effective internal control over financial reporting, and for its assessment of the effectiveness of internal control over financial reporting, included in the Trustee's Report on Internal Control Over Financial Reporting appearing under Item 9A. Our responsibility is to express opinions on these financial statements and on the Trust's internal control over financial reporting based on our audits (which was an integrated audit in 2012).

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audits to obtain reasonable assurance about whether the financial statements are free of material misstatement and whether effective internal control over financial reporting was maintained in all material respects. Our audits of the financial statements included examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. Our audit of internal control over financial reporting included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audits also included performing such other procedures as we considered necessary in the circumstances. We believe that our audits provide a reasonable basis for our opinions.

As described in Note 2, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

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

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

In our opinion, the financial statements referred to above present fairly, in all material respects, the financial position of the Trust at December 31, 2012 and 2011, and the distributable income and changes in trust corpus for the year ended December 31, 2012 and the six month period ended December 31, 2011 on the basis of accounting described in Note 2. Also in our opinion, the Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in Internal Control-Integrated Framework

issued by COSO.

/s/ PricewaterhouseCoopers LLP  
Tulsa, Oklahoma

March 15, 2013

54

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Table of Contents

CHESAPEAKE GRANITE WASH TRUST  
 STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS  
 (\$ in thousands)

	December 31, 2012	December 31, 2011
<b>ASSETS:</b>		
Cash and cash equivalents	\$1,159	\$1,216
Investment in royalty interests	487,793	487,793
Less: accumulated amortization	(59,331	) (5,350
Net investment in royalty interests	428,462	482,443
Total assets	\$429,621	\$483,659
<b>LIABILITIES AND TRUST CORPUS:</b>		
Loan from Chesapeake	\$—	\$200
Short-term derivative liability	3,276	7,604
Total short-term liabilities	3,276	7,804
Long-term derivative liability	4,808	12,937
Trust corpus; 35,062,500 common units and 11,687,500 subordinated units authorized and outstanding	421,537	462,918
Total liabilities and trust corpus	\$429,621	\$483,659

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

Table of Contents

CHESAPEAKE GRANITE WASH TRUST  
 STATEMENTS OF DISTRIBUTABLE INCOME  
 (\$ in thousands, except per unit data)

	Year Ended December 31, 2012	Six Months Ended December 31, 2011
<b>REVENUES:</b>		
Royalty income	\$ 127,335	\$ 29,334
Interest income	3	2
Total Revenues	127,338	29,336
<b>EXPENSES:</b>		
Production taxes	2,707	906
Trust administrative expenses	1,589	300
Derivative settlement loss	6,389	—
Cash reserves withheld	143	1,015
Total Expenses	10,828	2,221
Distributable income	\$ 116,510	\$ 27,115
Distributable income per common unit (35,062,500 units)	\$ 2.6265	\$ 0.5800
Distributable income per subordinated unit (11,687,500 units)	\$ 2.0892	\$ 0.5800

CHESAPEAKE GRANITE WASH TRUST  
 STATEMENTS OF CHANGES IN TRUST CORPUS  
 (\$ in thousands)

	Year Ended December 31, 2012	Six Months Ended December 31, 2011
TRUST CORPUS: Beginning of period	\$ 462,918	\$ 1
Issuance of trust units, net of issuance costs of \$27,312	—	409,688
Additional cash reserves	143	1,015
Conveyance of royalty interests	—	487,793
Consideration for investment in royalty interests	—	(409,688 )
Amortization of investment in royalty interests	(53,981 )	(5,350 )
Derivative liability at novation	—	(20,993 )
Change in derivative liability	12,457	452
Distributable income	116,510	27,115
Distributions paid to unitholders	(116,510 )	(27,115 )
TRUST CORPUS: End of period	\$ 421,537	\$ 462,918

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

Table of Contents

CHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS

1. Organization of the Trust

Chesapeake Granite Wash Trust (the “Trust”) is a statutory trust formed on June 29, 2011 by Chesapeake Energy Corporation (“Chesapeake”) 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 was created to own royalty interests (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 (a) Chesapeake’s interests in 69 existing horizontal wells (the “Producing Wells”), and (b) Chesapeake’s interests in 118 horizontal development wells (the “Development Wells”) that have since been, or that are to be, drilled on properties held by Chesapeake within an area of mutual interest (the “AMI”) in Washita County in western Oklahoma. Pursuant to a development agreement with the Trust, Chesapeake is obligated to drill, cause to be drilled or participate as a non-operator in the drilling of the 118 Development Wells by June 30, 2016. Additionally, based on Chesapeake’s assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake has retained an interest in each of the Producing Wells and Development Wells and currently operates 95% of the Producing Wells and the completed Development Wells and expects to operate approximately 90% of the remaining 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 interest in the Producing Wells (the “PDP Royalty Interest”) entitles 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, NGL and natural gas production attributable to Chesapeake’s net revenue interest in the Producing Wells. The royalty interest in the Development Wells (the “Development Royalty Interest”) entitles 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, NGL and natural gas 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 of its 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.

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 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. At the end of the fourth full calendar quarter following Chesapeake’s satisfaction of its drilling obligation with respect to the Development Wells, the subordinated units will automatically convert into common units

Table of Contents

CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS – (Continued)

on a one-for-one basis and Chesapeake's right to receive incentive distributions will terminate. 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.

The aggregate distributions paid in the year ended December 31, 2012 were \$2.6265 per common unit and \$2.0892 per subordinated unit. The first two distributions, paid on March 1, 2012 and May 31, 2012, were above the subordination threshold and below the incentive threshold for the corresponding distribution period. However, the distributable income available for distribution to unitholders with respect to the distributions paid on August 30, 2012 and November 29, 2012 were below the applicable subordination threshold. All of the subordinated units are held by Chesapeake. See "Risk and Uncertainties" in Note 2 below.

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, NGL and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by affiliates of Chesapeake. Cash distributions to unitholders will be increased or decreased by the effect of the Trust's derivative contracts and reduced by the Trust's general and administrative expenses. See "Derivative Contracts" in Note 3 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 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.

## 2. Basis of Presentation and Significant Accounting Policies

**Basis of Accounting.** Financial statements of the Trust differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America ("GAAP") as the Trust records revenues when received and expenses when paid and may also establish certain cash reserves for contingencies which would not be accrued in financial statements prepared in accordance with GAAP. This non-GAAP, comprehensive basis of accounting corresponds to the accounting principles permitted for royalty trusts by the SEC as specified by Staff Accounting Bulletin Topic 12:E, Financial Statements of Royalty Trusts.

Most accounting pronouncements apply to entities whose financial statements are prepared in accordance with GAAP, directing such entities to accrue or defer revenues and expenses in a period other than when such revenues were received or expenses were paid. Because the Trust's financial statements are prepared on the modified cash basis as described above, most accounting pronouncements are not applicable to the Trust's financial statements.

**Use of Estimates.** The preparation of financial statements requires the Trust to make estimates and assumptions that affect the reported amounts of assets, liabilities and Trust corpus during the reporting period. Significant estimates that impact the Trust's financial statements include estimates of proved oil and natural gas reserves, which are used to compute the Trust's amortization of Investment in Royalty Interests and, as necessary, to evaluate potential impairments of Investment in Royalty Interests and of the fair value of derivatives. Actual results could differ from those estimates.

**Risk and Uncertainties.** The Trust's revenue and distributions are substantially dependent upon the prevailing and future prices for oil, NGL and natural gas, each of which depends on numerous factors beyond the Trust's control such as economic conditions, regulatory developments and competition from other energy sources. Oil, NGL and natural

gas prices historically have been volatile, and may be subject to significant fluctuations in the future. The Trust's derivative contracts serve to mitigate the effect of this price volatility on a portion of the Trust's anticipated oil and NGL production through September 30, 2015. See Note 3 for the Trust's derivative contracts.

Additionally, the Trust's exposure to low prices for NGL and natural gas production volumes for the production periods from March 1, 2012 to August 31, 2012 resulted in per unit income available for distribution below the

58

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Table of Contents

CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS – (Continued)

applicable subordination threshold and, accordingly, the Trust paid a common unit distribution at the subordination threshold of \$0.6100 and a subordinated unit distribution of \$0.4819 on August 30, 2012, covering production from March 1, 2012 to May 31, 2012, and a common unit distribution at the subordination threshold of \$0.6300 and a subordinated unit distribution of \$0.2208 on November 29, 2012, covering production from June 1, 2012 to August 31, 2012. Sustained low commodity prices will reduce the Trust's revenues and distributable income available to unitholders, and may result in future distributions to common unitholders at or below the subordination threshold.

Chesapeake's ability to perform its obligations to the Trust will depend on its future financial condition and economic performance, ability to sell assets, ability to comply with the financial covenants contained in its debt instruments and access to capital, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control. If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on a drilling support lien (the "Drilling Support Lien") to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the Trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation and the maximum amount the Trust can recover in a foreclosure or other action was limited to approximately \$140.1 million as of December 31, 2012 and further reduced to \$126.3 million as of March 8, 2013. The maximum amount that may be recovered under the Drilling Support Lien will decrease as the remaining Development Wells are drilled and completed.

Delays and expenses associated with a foreclosure could reduce distributions to the Trust unitholders by reducing the amount of proceeds available for distribution and may result in the loss of acreage due to leasehold expirations. Any amounts actually recovered in a foreclosure action would be applied to completion of Chesapeake's drilling obligation, would not result in any distribution to the Trust unitholders and may be insufficient to drill the number of wells needed for the Trust to realize the full value of the Royalty Interests in the Development Wells.

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 could also be unable to provide support to the Trust through loans and performance of its management duties.

**Cash.** Cash equivalents include all highly liquid instruments with maturities of three months or less at the time of acquisition. The Trustee maintains a minimum cash reserve of \$1.0 million and may at the Trustee's discretion reserve funds for future expected administrative expenses.

**Investment in Royalty Interests.** The conveyance of the Royalty Interests to the Trust was accounted for as a transfer of properties between entities under common control and recorded at the historical cost of Chesapeake ("Investment in Royalty Interests"), which is based on an allocation of the historical net book value of Chesapeake's full cost pool according to the fair value of the Royalty Interests relative to the fair value of Chesapeake's proved reserves. The carrying value of the Trust's Investment in Royalty Interests will not necessarily be indicative of the fair value of such Royalty Interests. The Trust is not burdened by development costs of the Royalty Interests.

The Investment in Royalty Interests is amortized as a single cost center on a units-of-production basis over total proved reserves. Such amortization does not reduce distributable income, rather it is charged directly to Trust corpus. Revisions to estimated future units-of-production are treated on a prospective basis beginning on the date such revisions are known.

On a quarterly basis, the Trust evaluates the carrying value of the Investment in Royalty Interests under the full cost accounting method prescribed by the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, the carrying value of the Investment in Royalty Interests may not exceed an amount equal to the sum of the present

value (using a 10% discount rate) of the estimated future net revenues from proved reserves. Any write-downs resulting from the ceiling test will be non-cash charges to Trust corpus and will not affect distributable income. Derivatives. To mitigate a portion of the exposure to adverse market changes of oil prices and, to the extent oil production falls below the hedged oil volume, NGL prices, the Trust is party to derivative contracts with its hedge counterparty. See Note 3 for discussion of the derivative contracts currently outstanding.

Table of Contents

CHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

The Trust records gains or losses from the derivative contracts conveyed under the derivative contracts when proceeds are received or payments are made, respectively. Additionally, changes in the fair value of the derivative contracts are accounted for as an adjustment to Trust corpus and the fair value carried on the statement of assets, liabilities and trust corpus.

**Loan Commitment.** Pursuant to the Trust Agreement, 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 loan funds to the Trust necessary to pay such expenses. Such loans will be recorded as a liability on the statement of assets, liabilities and trust corpus until repaid. Loans neither increase or decrease distributions to unitholders, however, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid.

**Revenues and Expenses.** Revenues received by the Trust are net of existing royalties and overriding royalties associated with Chesapeake's interests and are reduced by certain post-production expenses, production taxes and other allowable expenses, such as the Trust's administrative expenses, in order to determine distributable income. The Royalty Interests are not burdened by field and lease operating expenses.

**3. Derivative Contracts**

The Trust uses derivative instruments to manage its exposure to variability in cash flow from changes in oil prices and, to the extent oil production falls below hedge oil volume, NGL prices. On November 16, 2011, Chesapeake novated the derivative contracts described in the table below to the Trust pursuant to which the Trust became party to derivative contracts covering a portion of its production from October 1, 2011 through September 30, 2015. These derivative contracts consist of fixed-price oil swaps, in which the Trust receives a fixed price and pays a floating market price, based on New York Mercantile Exchange settlement prices, to the counterparty for the underlying commodity of the derivative. As a party to these contracts, the Trust receives payments directly from its counterparty or be required to pay any amounts owed directly to its counterparty. All swaps are net settled based on the difference between the fixed-price payment and the floating-price payment. Settlements are due on a quarterly basis, including the first two months of the calendar quarter just ended and the last month of the calendar quarter prior to that one. Any payment due to or from such counterparty will be made by the 40th day following the end of the calendar quarter in which such payments become due.

The Trust's obligations to the counterparty under the derivative contracts are secured by proved reserves attributable to the Trust's interest in the Underlying Properties. The counterparty's obligations under the facility must be secured by cash or short-term U.S. Treasury instruments to the extent that any mark-to-market amounts owed to the Trust exceeds defined thresholds. Mark-to-market amounts did not exceed the defined thresholds as of December 31, 2012.

Table of ContentsCHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

As of December 31, 2012, the Trust had the following oil derivative contracts:

Production Quarter	Fixed-Price Oil Swaps		Fair Value (\$ in thousands)
	Volume (mbbl)	Weighted Avg. Price (per bbl)	
Q3 2012 <sup>(1)</sup>	60.9	86.83	(201 )
Q4 2012 <sup>(2)</sup>	185.5	86.98	(467 )
Q1 2013	182.2	87.37	(780 )
Q2 2013	184.3	87.60	(1,061 )
Q3 2013	187.9	87.79	(1,098 )
Q4 2013	184.2	87.99	(979 )
Q1 2014	179.8	88.08	(844 )
Q2 2014	180.3	88.21	(735 )
Q3 2014	178.8	88.34	(633 )
Q4 2014	174.3	88.45	(524 )
Q1 2015	171.0	88.59	(380 )
Q2 2015	175.4	88.76	(247 )
Q3 2015	153.6	88.90	(135 )
Total	2,198.2	\$88.03	\$(8,084 )

(1) Includes September 2012 production that was settled in February 2013.

(2) Includes October and November 2012 production that was settled in February 2013.

To the extent oil production falls below the hedged oil volume, the derivative contracts will also cover NGL production. Such estimated production of NGL is hedged with oil contracts using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. In 2012, NGL prices have decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the derivative contracts will not effectively mitigate the price risk of the Trust's NGL production.

In accordance with accounting guidance for derivatives and hedging, and because a legal right of set-off exists, the Trust has netted the value of its derivative contracts with the counterparty in the accompanying statement of assets, liabilities and trust corpus. Derivative liability reflected as short-term represents the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices as of December 31, 2012. The Trust does not apply hedge accounting to any of its derivative instruments, and therefore, any changes in the fair value of the derivative contracts prior to settlement will be accounted for as an adjustment to Trust corpus. Results of settled derivative contracts are reflected in distributable income in the period when paid. For the year ended December 31, 2012, the Trust settled derivative contracts that resulted in net payments to the counterparty of \$6.4 million.

#### 4. Income Taxes

The Trust is a Delaware statutory trust that is treated as a partnership for U.S. federal income tax purposes. The Trust is not required to pay federal or state income taxes. Accordingly, no provision for federal or state income tax has been made.

Trust unitholders are treated as partners of the Trust for U.S. federal income tax purposes. The Trust Agreement contains tax provisions that generally allocate the Trust's income, deductions and credits among the Trust unitholders in accordance with their percentage interests in the Trust. The Trust Agreement also sets forth the tax accounting

principles to be applied by the Trust.

61

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Table of Contents

CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS – (Continued)

5. Related Party Transactions

**Trustee Administrative Fee.** Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of \$175,000 to the Trustee, paid in equal quarterly installments. The administrative fee may be adjusted for inflation by no more than 3% in any calendar year beginning in 2015. As the Trust uses the modified cash basis of accounting, general and administrative expenses in the Trust's statements of distributable income for the year ended December 31, 2012 includes \$175,000 for quarterly administrative fees paid to the Trustee. The Trustee did not receive a fee for the six months ended December 31, 2011.

**Agreements with Chesapeake.** In connection with the initial public offering and the conveyance of the Royalty Interests to the Trust, the Trust entered into an administrative service agreement, a development agreement and a registration rights agreement with Chesapeake.

Pursuant to the administrative services agreement, 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, in equal quarterly installments, an annual fee of \$200,000, which will remain 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. Chesapeake was paid approximately \$303,000 and \$106,000 in fees and reimbursements in 2012 and 2011, respectively.

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. As hedge manager, Chesapeake also has authority to terminate, restructure or otherwise modify all or any portion of the derivative contracts to the extent that Chesapeake reasonably determines, acting in good faith, that the volumes hedged under such contracts exceed, or are expected to exceed, the combined estimated production attributable to the Royalty Interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake does not act as a fiduciary for the Trust and has no affirmative duty to modify any of the Trust's derivative contracts, except as required by the derivative contracts and the administrative services agreement. Moreover, the Trust will indemnify Chesapeake for any actions it takes in this regard.

The administrative services agreement will terminate upon the earliest to occur of (a) the date the Trust shall have dissolved and wound up its business and affairs 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.

The development agreement obligates Chesapeake to drill, cause to be drilled or participate as a non-operator in the drilling of the Development Wells on or prior to June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake has also agreed not to drill and complete, or permit any other person within its control to drill and complete, any well in the AMI other than the Development Wells until Chesapeake has met its obligation to drill the Development Wells.

In drilling the Development Wells, Chesapeake is required 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 (the "Reasonably Prudent Operator Standard"). Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties

to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells, the existing Development Wells, and other Colony Granite Wash producing wells outside of the AMI.

Under the development agreement, Chesapeake will be credited for drilling one full Development Well if the perforated length of the well is equal to or greater than 3,500 feet and Chesapeake's net revenue interest in the well

Table of Contents

CHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

is equal to 52.0%. For wells with a perforated length that is less than 3,500 feet, and for wells in which Chesapeake has a net revenue interest greater than or less than 52.0%, Chesapeake receives proportionate credit.

A wholly owned subsidiary of Chesapeake has granted to the Trust the Drilling Support Lien covering Chesapeake's retained interest in the AMI (except its interest in the Producing Wells, Development Wells and any other wells 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 maximum amount that may be obtained by the Trust pursuant to the Drilling Support Lien initially could not exceed \$262.7 million. As Chesapeake fulfills its drilling obligation over time, the total amount that may be recovered will be proportionately reduced and the completed Development Wells will be released from the lien. If Chesapeake does not fulfill its drilling obligation by June 30, 2016, the Trust may foreclose on any remaining interest in the AMI that is subject to the Drilling Support Lien. Any amounts actually recovered in a foreclosure action would be applied to the completion of Chesapeake's drilling obligation and would not result in any distribution to the Trust unitholders.

Chesapeake's drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. As of March 8, 2013, Chesapeake had drilled and completed, or caused to be drilled or completed, a total of 56 wells in the AMI (approximately 61.3 Development Wells as calculated under the development agreement), reducing the amount that may be recovered under the Drilling Support Lien to approximately \$126.3 million.

The Trust also entered into a registration rights agreement for the benefit of Chesapeake and certain of its affiliates (each, a "holder"). Pursuant to the registration rights agreement, the Trust agreed to register the Trust units held by each such holder for resale under the Securities Act of 1933, as amended. In connection with the preparation and filing of any registration statement, Chesapeake will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust, and any underwriting discounts and commissions, which will be borne by the seller of the Trust units. Specifically, the Trust agreed:

subject to certain lock-up restrictions, to use its reasonable best efforts to file a registration statement, including, if so requested, a shelf registration statement, with the SEC as promptly as practicable following receipt of a notice requesting the filing of a registration statement from holders representing a majority of the then outstanding registrable Trust units;

to use its reasonable best efforts to cause the registration statement or shelf registration statement to be declared effective under the Securities Act as promptly as practicable after the filing thereof; and

to continuously maintain the effectiveness of the registration statement under the Securities Act for 90 days (or for three years if a shelf registration statement is requested) after the effectiveness thereof or until the Trust units covered by the registration statement have been sold pursuant to such registration statement or until all registrable Trust units: have been sold pursuant to Rule 144 under the Securities Act if the transferee thereof does not receive "restricted securities";

have been sold in a private transaction in which the transferor's rights under the registration rights agreement are not assigned to the transferee of the Trust units; or

become eligible for resale pursuant to Rule 144 (or any similar rule then in effect under the Securities Act).

The holders will have the right to require the Trust to file no more than five registration statements in aggregate. In connection with the preparation and filing of any registration statement, Chesapeake will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust, and any underwriting discounts and commissions, which will be borne by the seller of the Trust units.

**Loan Commitment.** Pursuant to the Trust Agreement, 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 loan 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 current liabilities arising in the ordinary course of the Trust's business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans

Table of Contents

## CHESAPEAKE GRANITE WASH TRUST

## NOTES TO FINANCIAL STATEMENTS – (Continued)

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. As of December 31, 2011, a \$200,000 non-interest bearing loan was outstanding with Chesapeake, which loan was repaid in February 2012.

## 6. Fair Value Measurement

Certain financial instruments are reported at fair value on the statement of assets, liabilities and trust corpus. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. The Trust uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

Derivatives. The fair value of our derivatives is based on third-party pricing models which utilize inputs that are either readily available in the public market, such as oil forward curves and discount rates, or can be corroborated from active markets or broker quotes. These values are then compared to the values given by our counterparty for reasonableness. Since commodity swaps do not include optionality and therefore have no unobservable inputs, they are classified as Level 2.

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2012:

	Quoted Prices in Active Markets (Level 1) (\$ in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative liabilities	\$—	\$(8,084)	) \$—	\$(8,084)
Total	\$—	\$(8,084)	) \$—	\$(8,084)

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of December 31, 2011:

	Quoted Prices in Active Markets (Level 1) (\$ in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative liabilities	\$—	\$(20,541)	) \$—	\$(20,541)
Total	\$—	\$(20,541)	) \$—	\$(20,541)

Fair Value of Other Financial Instruments. The estimated fair value of financial instruments is made in accordance with accounting guidance for financial instruments. The carrying values of financial instruments comprising cash and cash equivalents approximate fair values due to the short-term maturities of these instruments.

Table of ContentsCHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

## 7. Distributions to Unitholders

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's expenses, approximately 60 days following the completion of each quarter through (and including) the quarter ending June 30, 2031. On November 7, 2012, the Trust declared a cash distribution of approximately \$25 million, or \$0.6300 per common unit and \$0.2208 per subordinated unit, for the three-month period ended September 30, 2012 and covering production from June 1, 2012 through August 31, 2012, to record unitholders as of November 19, 2012. The distribution was paid on November 29, 2012.

On August 10, 2012, the Trust declared a cash distribution of approximately \$27 million, or \$0.6100 per common unit and \$0.4819 per subordinated unit, for the three-month period ended June 30, 2012 and covering production for the period from March 1, 2012 to May 31, 2012. The distribution was paid on August 30, 2012 to record unitholders as of August 20, 2012.

On May 10, 2012, the Trust declared a cash distribution of approximately \$31 million, or \$0.6588 per unit, for the three-month period ended March 31, 2012 and covering production for the period from December 1, 2011 to February 29, 2012. The distribution was paid on May 31, 2012 to record unitholders as of May 21, 2012.

On February 8, 2012, the Trust declared a cash distribution of approximately \$34 million, or \$0.7277 per unit, for the three-month period ended December 31, 2011 and covering production for the period from September 1, 2011 to November 30, 2011. The distribution was paid on March 1, 2012 to record unitholders as of February 20, 2012.

## 8. Supplemental Information on Oil and Natural Gas Producing Activities (Unaudited)

Net Capitalized Costs. Evaluated and unevaluated capitalized costs related to the Trust's oil, NGL and natural gas producing activities are summarized as follows:

	As of December 31, 2012 (\$ in thousands)	As of December 31, 2011
Oil, NGL and natural gas properties:		
Proved	\$487,793	\$487,793
Unproved	—	—
Total	487,793	487,793
Less accumulated amortization	(59,331	) (5,350
Net capitalized costs	\$428,462	\$482,443

The Royalty Interests conveyed to the Trust by Chesapeake consist of interests in proved properties only. The Trust capitalized approximately \$487.8 million for the properties conveyed to the Trust concurrent with the initial public offering. The Royalty Interests were conveyed at the historical cost of the Royalty Interests to Chesapeake. The historical cost to Chesapeake was determined by allocating the historical net book value of Chesapeake's full cost pool according to the fair value of the Royalty Interests relative to the fair value of Chesapeake's proved reserves.

Costs Incurred in Oil and Natural Gas Drilling and Completion and Investment in Royalty Interest. Costs incurred in oil and natural gas drilling and completion, acquisition and divestiture activities which have been capitalized are limited to the \$487.8 million of initial investment in proved properties at the inception of the Trust. The Trust will not acquire or dispose of properties and is not burdened with drilling and completion costs.

Results of Operations from Oil and Natural Gas Producing Activities. Chesapeake's results of operations from oil and natural gas producing activities for the Trust's interest are presented below for 2012 and 2011. The following table includes revenues and expenses associated directly with the Trust's oil and natural gas producing activities. Production expenses and production taxes are deducted by Chesapeake prior to remittance of royalty income to the Trust. The

65

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Table of ContentsCHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

following calculation does not include any interest income or general and administrative costs and, therefore, is not necessarily indicative of distributable income:

	Year ended December 31, 2012 (\$ in thousands)	Six months ended December 31, 2011
Sales of oil, NGL and natural gas	\$ 127,335	\$ 29,334
Production expenses <sup>(1)</sup>	—	—
Production taxes	(2,707	) (906
Depletion and depreciation	(53,981	) (5,350
Income tax provision <sup>(1)</sup>	—	—
Royalty income from oil and natural gas producing activities	\$ 70,647	\$ 23,078

(1)The Trust does not bear any operating costs and is not subject to federal or state income taxes.

The following oil, NGL and natural gas information was prepared on an accrual basis, which is the basis upon which Chesapeake maintains its records and is different from the modified cash basis on which the Trust financial statements are prepared. A reconciliation of information presented on the modified cash basis to the accrual basis is as follows:

Year ended December 31, 2012	Modified Cash Basis <sup>(1)</sup>	For the period		Accrual Basis <sup>(2)</sup>
		September 1, 2011 to December 31, 2011	September 1, 2012 to December 31, 2012	
<b>Production Data:</b>				
Oil (m bbl)	673	(218	) 194	649
NGL (m bbl)	1,234	(384	) 434	1,284
Natural Gas (mmcf)	12,179	(3,751	) 4,010	12,438
Total (m boe)	3,937	(1,228	) 1,297	4,006
Royalty Income (in thousands)	\$ 127,335	\$(45,281	)\$ 39,154	\$ 121,208
Production Taxes (in thousands)	(2,707	) 1,004	(926	) (2,629
	\$ 124,628	\$(44,277	)\$ 38,228	\$ 118,579

(1) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses included in Chesapeake's 2012 net revenue distributions to the Trust. Represents oil and natural gas production from September 1, 2011 to August 31, 2012.

(2) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis, from January 1, 2012 through December 31, 2012, a portion of which will be reflected on the modified cash basis in distributable income in subsequent quarters.

Table of ContentsCHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

Six months ended December 31, 2011	For the period		
	Modified Cash Basis <sup>(1)</sup>	September 1, 2011 to December 31, 2011	Accrual Basis <sup>(2)</sup>
<b>Production Data</b>			
Oil (m bbl)	133	218	351
NGL (m bbl)	225	384	609
Natural Gas (mmcf)	2,172	3,751	5,923
Total (m boe)	720	1,228	1,948
Royalty Income (in thousands)	\$29,334	\$45,281	\$74,615
Production Taxes (in thousands)	(906)	(1,004)	(1,910)
	\$28,428	\$44,277	\$72,705

(1) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses included in Chesapeake's 2011 net revenue distributions to the Trust. Represents oil and natural gas production from July 1, 2011 to August 31, 2011.

(2) Oil and natural gas volumes attributable to the Royalty Interests and related revenues and expenses, presented on an accrual basis, from July 1, 2011 through December 31, 2011 on of which will be reflected under the modified cash basis in distributable income in subsequent quarters.

Estimated Oil and Natural Gas Reserve Quantities. The Trust's independent petroleum engineering firm, Ryder Scott Company, L.P. ("Ryder Scott"), estimated all of the proved reserves as of December 31, 2012 for the Royalty Interest. The qualifications of the technical person at Ryder Scott Company, L.P. primarily responsible for overseeing his firm's 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 engineer in the state of Texas
- Bachelor of Science degree in Electrical Engineering
- member in good standing of the Society of Petroleum Engineers and the Society of Petroleum Evaluation Engineers

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. Existing economic conditions include prices and costs at which economic producibility from a reservoir is to be determined. The price is calculated using the average price during the 12-month period prior to the ending date of the period covered by the report, determined as an unweighted arithmetic average of the first-day-of-the-month price for each month within such period, unless prices are defined by contractual arrangements, excluding escalations based upon future conditions. The project to extract the hydrocarbons must have commenced or the operator must be reasonably certain that it will commence the project within a reasonable time. The area of the reservoir considered as proved includes: (i) the area identified by drilling and limited by fluid contacts, if any, and (ii) adjacent undrilled portions of the reservoir that can, with reasonable certainty, be judged to be continuous with it and to contain economically producible natural gas or oil 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 establish 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 natural gas cap, proved oil reserves may be assigned in the structurally higher portions of the reservoir only if geoscience, engineering or performance data and reliable technology establish the higher contact with reasonable certainty. Reserves which can be produced economically through application of improved recovery techniques (including, but not limited to, fluid injection) are included in the proved classification when: (i) successful testing by a pilot project in an area of the reservoir with properties no more favorable than in the reservoir as a whole,

Table of ContentsCHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

the operation of an installed program in the reservoir or an analogous reservoir, or other evidence using reliable technology establishes the reasonable certainty of the engineering analysis on which the project or program was based; and (ii) the project has been approved for development by all necessary parties and entities, including governmental entities.

Developed oil and natural gas reserves are reserves of any category 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.

The information below on our oil and natural gas reserves attributed to the Royalty Interests is presented in accordance with regulations prescribed by the SEC in effect as of the date of such estimates. Our reserve estimates are generally based upon extrapolation of historical production trends, analogy to similar properties and volumetric calculations. Accordingly, these estimates will change as future information becomes available and as commodity prices change. Such changes could be material and could occur in the near term.

Presented below is a summary of changes in estimated reserves of the Royalty Interests for the year ended December 31, 2012 and six months ended December 31, 2011.

	Oil (mdbl)	NGL (mdbl)	Gas (mmcf)	Total (mboe)
December 31, 2012				
Beginning of period, accrual basis	5,928	13,661	135,567	42,184
Extensions, discoveries and other additions	234	471	5,018	1,541
Revisions of previous estimates, price <sup>(1)</sup>	(157)	) (357	) (3,558	) (1,106 )
Revisions of previous estimates, other <sup>(1)</sup>	(1,783	) (3,290	) (32,017	) (10,410 )
Production	(649	) (1,284	) (12,438	) (4,006 )
Proved reserves, end of period	3,573	9,201	92,572	28,203
Proved developed reserves:				
Beginning of period	2,076	6,021	58,724	17,884
End of period	1,708	5,635	56,224	16,714
Proved undeveloped reserves:				
Beginning of period	3,852	7,640	76,843	24,300
End of period	1,865	3,566	36,348	11,489

(1) During 2012, the Trust recorded downward reserve revisions of 10,410 Mboe to the December 31, 2011 estimates of reserves. Included in the revisions were 1,106 mboe of downward revisions resulting from lower natural gas prices in 2012 and 10,410 mboe of downward revisions resulting from changes to previous estimates. Lower prices decrease the economic lives of the underlying natural gas and oil properties and thereby decrease the estimated future reserves. The non-price related revisions were primarily due to current results being below expectations, primarily as a result of higher than expected pressure depletion within certain areas of the Granite Wash AMI.

Table of ContentsCHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

	Oil (mdbl)	NGL (mdbl)	Gas (mmcf)	Total (mboe)
December 31, 2011				
Conveyance of Royalty Interest, July 1, 2011	6,235	14,554	140,861	44,266
Extensions, discoveries and other additions	—	—	—	—
Revisions of previous estimates, price	—	—	—	—
Revisions of previous estimates, other	44	(284)	)629	(134)
Production	(351)	)609	)5,923	)1,948
Proved reserves, end of period	5,928	13,661	135,567	42,184
Proved developed reserves:				
Beginning of period	2,233	6,235	60,536	18,557
End of period	2,076	6,021	58,724	17,884
Proved undeveloped reserves:				
Beginning of period	4,002	8,319	80,325	25,709
End of period	3,852	7,640	76,843	24,300

Presented below is a summary of the adjustment to the estimated reserves attributable to the Royalty Interests to adjust the reserves to the balance attributable to the Trust under the modified cash basis of accounting.

	Oil (mdbl)	NGL (mdbl)	Gas (mmcf)	Total (mboe)
December 31, 2012				
Proved reserves, accrual basis	3,573	9,201	92,572	28,203
Production September 1 - December 31, 2012 <sup>(1)</sup>	194	434	4,010	1,297
Adjusted Proved reserves, on a modified cash basis	3,767	9,635	96,582	29,500

<sup>(1)</sup> As of December 31, 2012 the Trust had not received royalty income associated with the production sold from September 1 - December 31, 2012. The reserves are adjusted to include such amount in proved reserves.

	Oil (mdbl)	NGL (mdbl)	Gas (mmcf)	Total (mboe)
December 31, 2011				
Proved reserves, accrual basis	5,928	13,661	135,567	42,184
Production September 1 - December 31, 2011 <sup>(1)</sup>	218	384	3,751	1,228
Adjusted Proved reserves, on a modified cash basis	6,146	14,045	139,318	43,412

<sup>(1)</sup> As of December 31, 2012 the Trust had not received royalty income associated with the production sold from September 1 - December 31, 2011. The reserves are adjusted to include such amount in proved reserves.

Standardized Measure of Discounted Future Net Cash Flows. Accounting Standards Topic 932 prescribes guidelines for computing a standardized measure of future net cash flows and changes therein relating to estimated proved reserves. Chesapeake has advised the Trustee that Chesapeake followed these guidelines, which are briefly discussed below.

Future cash inflows and future production costs as of December 31, 2012 were determined by applying the trailing average 12-month prices and year-end costs to the estimated quantities of oil and natural gas to be produced. Actual future prices and costs may be materially higher or lower than the 12-month average prices and year-end costs used.

For each year, estimates are made of quantities of proved reserves and the future periods during which they are

69

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Table of ContentsCHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

expected to be produced based on continuation of the economic conditions applied for such year. The resulting future net cash flows are reduced to present value amounts by applying a 10% annual discount factor.

The assumptions used to compute the standardized measure are those prescribed by the Financial Accounting Standards Board and, as such, do not necessarily reflect our expectations of actual revenue to be derived from those reserves nor their present worth. The limitations inherent in the reserve quantity estimation process, as discussed previously, are equally applicable to the standardized measure computation since these estimates reflect the valuation process.

The following summary sets forth our future net cash flows relating to proved oil and natural gas reserves based on the standardized measure:

	December 31, 2012		December 31, 2011
	(\$ in thousands)		
Future cash inflows	\$ 778,663	(1)	\$ 1,546,856 (2)
Future production costs <sup>(3)</sup>	(37,510	)	(74,035 )
Future development costs <sup>(4)</sup>	—		—
Future income tax provisions <sup>(5)</sup>	—		—
Future net cash flows	741,153		1,472,821
Less effect of a 10% discount factor	(298,249	)	(625,661 )
Standardized measure of discounted future net cash flows	\$ 442,904		\$ 847,160

(1) Calculated using prices of \$2.76 per mcf of natural gas and \$94.84 per bbl of oil, before field differentials.

Including the effect of price differential adjustments, the prices used in computing the reserves attributable to the Royalty Interests as of December 31, 2012 were \$1.60 per mcf of natural gas, \$90.89 per barrel of oil and \$33.21 per barrel of NGL.

(2) Calculated using prices of \$4.12 per mcf of natural gas and \$95.97 per bbl of oil, before field differentials. Including the effect of price differential adjustments, the prices used in computing the reserves attributable to the Royalty Interests as of December 31, 2011 were \$3.05 per mcf of natural gas, \$91.65 per barrel of oil and \$43.19 per barrel of NGL.

(3) Future production costs include the Trust's proportionate share of production taxes and post production costs. The Trust does not bear any operational costs related to the wells.

(4) Future net cash flow has been calculated without deduction for future development costs as the Trust does not bear those costs.

(5) No provision for federal or state income taxes has been provided for in the calculation because taxable income is passed through to the unitholders of the Trust.

Table of ContentsCHESAPEAKE GRANITE WASH TRUST  
NOTES TO FINANCIAL STATEMENTS – (Continued)

Changes in Standardized Measure of Discounted Future Net Cash Flows. The following schedule reconciles the changes for the year ended December 31, 2012 and six months ended December 31, 2011 in the standardized measure of discounted future net cash flows relating to proved reserves:

	Year Ended December 31, 2012 (\$ in thousands)	Six Months Ended December 31, 2011	
Standardized measure, beginning of period	\$847,160	\$811,140	
Sales of oil and gas produced, net of production costs	(118,579)	(72,705)	)
Net changes in prices and production costs	(164,294)	54,646	)
Revision of previous quantity estimates	(161,472)	(3,294)	)
Purchase of reserves-in-place	—	600	
Accretion of discount	84,716	40,557	
Other	(44,627)	16,216	)
Standardized measure, end of period	\$442,904	\$847,160	

## 9. Quarterly Financial Results (unaudited)

The following is a summary of royalty income, interest income and distributable income by quarter for 2012 and 2011 (in thousands except per unit amounts):

Year Ended December 31, 2012	Q1	Q2	Q3	Q4	2012
Royalty Income	\$36,070	\$34,554	\$30,955	\$25,756	\$127,335
Interest Income	\$1	\$1	\$1	\$—	\$3
Distributable income	\$34,019	\$30,801	\$27,020	\$24,670	\$116,510
Distributable income per common unit	\$0.7277	\$0.6588	\$0.6100	\$0.6300	\$2.6265
Distributable income per subordinated unit	\$0.7277	\$0.6588	\$0.4819	\$0.2208	\$2.0892

## Six Months Ended December 31, 2011

	Q1	Q2	Q3	Q4	2011
Royalty Income	\$—	\$—	\$—	\$29,334	\$29,334
Interest Income	\$—	\$—	\$—	\$2	\$2
Distributable income	\$—	\$—	\$—	\$27,115	\$27,115
Distributable income per common unit	\$—	\$—	\$—	\$0.5800	\$0.5800
Distributable income per subordinated unit	\$—	\$—	\$—	\$0.5800	\$0.5800

## 10. Subsequent Events

On February 8, 2013, the Trust declared a cash distribution of \$0.6700 per common unit and \$0.3772 per subordinated unit, consisting of proceeds attributable to production from September 1, 2012 to November 30, 2012, to record unitholders as of February 19, 2013. The distribution was paid on March 1, 2013. The Trust's quarterly calculated income available for distribution was \$0.5968 per unit, which was \$0.0732 below the subordination threshold. As a result, the distribution per common unit was the subordination threshold of \$0.6700 for the quarter. Distributable income attributable to production from September 1, 2012 to November 30, 2012 was calculated as follows (in thousands except for unit and per unit amounts):



Table of Contents

CHESAPEAKE GRANITE WASH TRUST  
 NOTES TO FINANCIAL STATEMENTS – (Continued)

Revenues:	
Royalty income <sup>(1)</sup>	\$29,462
Total Revenues	\$29,462
Expenses:	
Production taxes	587
Trust administrative expenses <sup>(2)</sup>	366
Derivative settlement loss	609
Total Expenses	1,562
Distributable income available to unitholders	\$27,900
Distributable income per common unit (35,062,500 units issued and outstanding)	\$0.6700
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	\$0.3772

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

ITEM 9. Changes in and Disagreements with Accountants on Accounting and Financial Disclosures

None.

ITEM 9A. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the "Exchange Act"), designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC's rules and forms. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by several parties including, without limitation, Chesapeake and the independent reserve engineer to The Bank of New York Mellon Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust's periodic reports as appropriate to allow timely decisions regarding required disclosures. As of the end of the period covered by this Annual Report, the Trustee carried out an evaluation of the Trustee's disclosure controls and procedures. Michael J. Ulrich, as Trust Officer of the Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the Trust Agreement, (ii) the administrative services agreement, (iii) the development agreement and (iv) the conveyances granting the Royalty Interests, the Trustee's disclosure controls and procedures related to the Trust necessarily rely on (a) information provided by Chesapeake, including information relating to results of operations, the status of drilling of the Development Wells, the costs and revenues attributable to the Trust's interests under the conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the underlying properties and the Royalty Interests, and (b) conclusions and reports regarding reserves by the Trust's independent reserve engineers. Other than reviewing the financial and other information provided to the Trust by Chesapeake and the independent reserve engineer, the Trustee made no independent or direct verification of this financial or other information.

Changes in Internal Control over Financial Reporting. During the year ended December 31, 2012, there has been no change in the Trustee's internal control over financial reporting that has materially affected, or is reasonably likely to materially affect, the Trustee's internal control over financial reporting related to the Trust. The Trustee notes for purposes of clarification that it has no authority over, and makes no statement concerning, the internal control over financial reporting of Chesapeake.

Trustee's Report on Internal Control Over Financial Reporting. The Trustee is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Exchange Act Rules 13a-15(f) and 15d-15(f), by the Trust. The Trust's internal control over financial reporting is a process designed under the supervision of the Trustee to provide reasonable assurance regarding the reliability of financial reporting and the preparation of the Trust's financial statements for external purposes in accordance with generally accepted accounting principles.

As of December 31, 2012, the Trustee assessed the effectiveness of the Trust's internal control over financial reporting based on the criteria for effective internal control over financial reporting established in "Internal Control-Integrated Framework," issued by the Committee of Sponsoring Organizations of the Treadway Commission. Based on that assessment, the Trustee determined that the Trust maintained effective internal control over financial reporting as of December 31, 2012, based on those criteria.

PricewaterhouseCoopers LLP, the independent registered public accounting firm that audited the financial statements of the Trust included in this Annual Report, has also audited the effectiveness of the Trust's internal control over financial reporting as of December 31, 2012, as stated in their accompanying report included in Item 8.

ITEM 9B. Other Information

None.

73

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Table of Contents

PART III

ITEM 10. Directors, Executive Officers and Corporate Governance

The Trust has no directors or executive officers. The Trustee is a corporate trustee that may be removed by the affirmative vote of the holders of not less than a majority of the outstanding Trust units at a meeting at which a quorum is present.

Section 16(a) Beneficial Ownership Reporting Compliance

Section 16(a) of the Exchange Act requires the holders of more than 10 percent of the Trust units to file with the SEC reports regarding their ownership and changes in ownership of the Trust units. The Trustee is not aware of any 10 percent unitholder having failed to comply with all Section 16(a) filing requirements in 2012. In making these statements, the Trustee has relied upon examination of the copies of documents, to the extent there were any, provided to the Trust.

Audit Committee and Nominating Committee

Because the Trust does not have a board of directors, it does not have an audit committee, an audit committee financial expert or a nominating committee.

Code of Ethics

The Trust does not have a principal executive officer, principal financial officer, principal accounting officer or controller and, therefore, has not adopted a code of ethics applicable to such persons. However, employees of the Trustee must comply with the Trustee's code of ethics.

ITEM 11. Executive Compensation

During the year ended December 31, 2012, the Trustee received an administrative fee of \$175,000 from the Trust. The Trust does not have any executive officers, directors or employees. Because the Trust does not have a board of directors, it does not have a compensation committee.

ITEM 12. Security Ownership of Certain Beneficial Owners and Management and Related Unitholder Matters

(a) Security Ownership of Certain Beneficial Owners

Based on filings with the SEC, the Trustee is not aware of any holders of 5% or more of the units except as set forth below. The following information has been obtained from filings with the SEC on Schedule 13D.

Beneficial Owner	Trust Units Beneficially Owned	Percent of Class
Chesapeake Energy Corporation <sup>(1)</sup>	12,062,500 Common Units	34.4%
Chesapeake Energy Corporation <sup>(1)</sup>	11,687,500 Subordinated Units	100%

(1) Chesapeake Energy Corporation, located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118, is the ultimate parent company of Chesapeake Exploration, L.L.C., which is the owner of the common units and subordinated units reported in the table above. Chesapeake may be deemed to beneficially own the common units and subordinated units owned by Chesapeake Exploration, L.L.C. Chesapeake has an Investment Committee consisting of Aubrey K. McClendon, Domenic J. ("Nick") Dell'Osso, Jr. and Jennifer M. Grigsby that will exercise voting and investment control with respect to Chesapeake's common and subordinated units.

(b) Security Ownership of Management

Not Applicable

(c) Changes in Control

The registrant knows of no arrangement, including any pledge by any person of securities of the registrant or its parent, the operation of which may at a subsequent date result in a change of control of the registrant.

74

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Table of Contents

ITEM 13. Certain Relationships and Related Transactions and Director Independence

During December 2011, the Trustee determined that the Trust's cash on hand was not sufficient to fund its current general and administrative liabilities due. Accordingly, the Trust entered into a transaction with Chesapeake in the ordinary course of business, whereby Chesapeake advanced \$200,000 to the Trust on December 22, 2011, and the Trust repaid Chesapeake on February 3, 2012.

Under the terms of the Trust agreement, the Trust pays an annual administrative fee to the Trustee of \$175,000 (which may be adjusted beginning on January 1, 2015), paid in four quarterly installments of \$43,750 each and is billed in arrears. Since the Trust began operations in the fourth quarter of 2011, no fees were charged for the fourth quarter of 2011. As the Trust uses the modified cash basis of accounting, general and administrative expenses in the Trust's statements of distributable income for the year ending December 31, 2012 includes \$175,000 for quarterly administrative fees paid to the Trustee. The Trustee did not receive a fee for the year ended December 31, 2011.

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, on a quarterly basis, a total annual fee of \$200,000, which will remain fixed for the life of the Trust. Chesapeake will also be 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. As hedge manager, Chesapeake also has authority to terminate, restructure or otherwise modify all or any portion of the derivative contracts to the extent that Chesapeake reasonably determines, acting in good faith, that the volumes hedged under such contracts exceed, or are expected to exceed, the combined estimated production attributable to the Royalty Interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake is not acting as a fiduciary for the Trust and has no affirmative duty to modify any of the Trust's derivative contracts, except as required by the derivative contracts. Moreover, under the Trust Agreement, Chesapeake is indemnified by the Trust for any actions it takes in this regard.

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.

Registration Rights Agreement

On November 16, 2011, the Trust entered into a registration rights agreement for the benefit of Chesapeake and certain of its affiliates (each, a "holder"). Pursuant to the registration rights agreement, the Trust agreed, for the benefit of each holder, to register the Trust units held by each such holder for resale under the Securities Act. Specifically, the Trust agrees:

subject to certain lock-up restrictions, to use its reasonable best efforts to file a registration statement, including, if so requested, a shelf registration statement, with the SEC as promptly as practicable following receipt of a notice requesting the filing of a registration statement from holders representing a majority of the then outstanding registrable trust units;

• to use its reasonable best efforts to cause the registration statement or shelf registration statement to be declared effective under the Securities Act as promptly as practicable after the filing thereof; and

• to continuously maintain the effectiveness of the registration statement under the Securities Act for 90 days (or for three years if a shelf registration statement is requested) after the effectiveness thereof

## Table of Contents

or until the Trust units covered by the registration statement have been sold pursuant to such registration statement or until all registrable Trust units:

- have been sold pursuant to Rule 144 under the Securities Act if the transferee thereof does not receive “restricted securities”;
- have been sold in a private transaction in which the transferor's rights under the registration rights agreement are not assigned to the transferee of the Trust units; or
- become eligible for resale pursuant to Rule 144 (or any similar rule then in effect under the Securities Act).

The holders will have the right to require the Trust to file no more than five registration statements in aggregate.

In connection with the preparation and filing of any registration statement, Chesapeake will bear all costs and expenses incidental to any registration statement, excluding certain internal expenses of the Trust, which will be borne by the Trust, and any underwriting discounts and commissions, which will be borne by the seller of the Trust units.

## Development Agreement

On November 16, 2011, the Trust entered into a development agreement with Chesapeake, effective July 1, 2011, that obligates Chesapeake to drill and complete, or cause to be drilled and completed, all of the Development Wells on or prior to June 30, 2016. Additionally, until Chesapeake has met its obligation to drill the Development Wells, Chesapeake agreed not to drill and complete, or permit any other person within its control to drill and complete, any well in the AMI other than the Development Wells. A wholly owned subsidiary of Chesapeake granted to the Trust a lien (the "Drilling Support Lien") on its retained interest in the AMI (except the Producing Wells and any other wells that are already producing and 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 maximum amount that may be obtained by the Trust pursuant to the Drilling Support Lien or through its exercise of other remedies against Chesapeake for failure to meet its drilling obligation initially could not exceed \$262.7 million. As Chesapeake fulfills its drilling obligation over time, the total amount that may be recovered will be proportionately reduced and the completed Development Wells will be released from the lien. If Chesapeake does not fulfill its drilling obligation by June 30, 2016, the Trust may foreclose on any remaining interest in the AMI that is subject to the Drilling Support Lien. Any amounts actually recovered in a foreclosure action would be applied to the completion of Chesapeake's drilling obligation and would not result in any distribution to the Trust unitholders.

Under the development agreement, Chesapeake will be credited for drilling one full Development Well if the perforated length of the well is equal to or greater than 3,500 feet and Chesapeake's net revenue interest in the well is equal to 52.0%. For wells with a perforated length that is less than 3,500 feet, and for wells in which Chesapeake has a net revenue interest greater than or less than 52.0%, Chesapeake receives proportionate credit.

Given that Chesapeake's actual net revenue interest in each Development Well may be greater than or less than 52.0% and the perforated length of each well drilled may be less than 3,500 feet, Chesapeake may be required to drill more or less than 118 wells in order to fulfill its drilling obligation.

In drilling the Development Wells, Chesapeake is required to adhere to the Reasonably Prudent Operator Standard. Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells and other Colony Granite Wash producing wells outside of the AMI.

Following the drilling of each Development Well, Chesapeake is obligated to attempt to complete each such well that reasonably appears to Chesapeake, acting in accordance with the Reasonably Prudent Operator Standard, to be capable of producing in quantities sufficient to pay drilling, completion, equipping and operating costs. Following successful completion of such wells, Chesapeake is obligated to equip such wells for production and connect such wells to a gathering line, pipeline or other storage or marketing facility and commence production. If Chesapeake is unable to successfully complete a Development Well, Chesapeake is obligated to plug and abandon such well to the extent required by law.

Chesapeake may, and anticipates that it will, rely on third-party operators to fulfill a portion of its drilling, completion and equipping obligation. The Trust will not bear any of the costs of drilling, completing and equipping the Development

Table of Contents

Wells that Chesapeake drills or causes to be drilled. Until Chesapeake has satisfied its drilling obligation, it will not be permitted to drill or complete any well in the Colony Granite Wash formation on lease acreage included within the AMI for its own account. 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's drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. As of March 8, 2013, Chesapeake had drilled and completed a total of 56 wells in the AMI (approximately 61.3 Development Wells as calculated under the development agreement), reducing the amount that may be recovered under the Drilling Support Lien to approximately \$126.3 million, and had drilled, or caused to be drilled, two additional wells in the AMI that were awaiting completion.

## ITEM 14. Principal Accountant Fees and Services

Estimated fees for services performed by PricewaterhouseCoopers, L.L.P. for the years ended December 31, 2012 and December 31, 2011 are:

	2012	2011
Audit Fees <sup>(1)</sup>	\$203,000	\$175,000
Audit-Related Fees	—	—
Tax Fees	466,245	307,276
All Other Fees	—	—
Total	\$669,245	\$482,276

(1) Fees for audit services in 2012 included fees for the reviews of the Trust's quarterly financial statements.

As a modified cash basis entity the Trust will expense these fees when paid.

As referenced in Item 10, Directors, Executive Officers and Corporate Governance, above, the Trust has no audit committee, and as a result, has no audit committee pre-approval policy with respect to fees paid to PricewaterhouseCoopers, L.L.P.

Table of Contents

## PART IV

## ITEM 15. Exhibits and Financial Statement Schedules

(a) The following documents are filed as part of this Annual Report:

Financial Statements. Chesapeake Granite Wash Trust's financial statements are included in Item 8 of this Annual Report.

Exhibits. The following exhibits are filed herewith pursuant to the requirements of Item 601 of Regulation S-K:

Exhibit Number	Exhibit Description	Incorporated by Reference			Filing Date	Filed Herewith	Furnished Herewith
		Form	SEC File Number	Exhibit			
3.1	Certificate of Trust of Chesapeake Granite Wash Trust. Amended and Restated Trust Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake	S-1	333-175395	3.1	7/7/2011		
3.2	Exploration, L.L.C., The Bank of New York Mellon Trust Company, N.A., as Trustee, Trustee and The Corporation Trust Company, as Delaware Trustee.	8-K	001-35343	3.1	11/21/2011		
10.1	Perpetual Overriding Royalty Interest Conveyance (PDP), dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.1	11/21/2011		
10.2	Perpetual Overriding Royalty Interest Conveyance (PUD), dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.2	11/21/2011		
10.3	Term Overriding Royalty Interest Conveyance (PDP), dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake E&P Holding Corporation.	8-K	001-35343	10.3	11/21/2011		
10.4	Term Overriding Royalty Interest Conveyance (PUD), dated as of November 16, 2011, by and	8-K	001-35343	10.4	11/21/2011		

<p>between Chesapeake Exploration, L.L.C. and Chesapeake E&amp;P Holding Corporation.</p>					
<p>Assignment of Term Overriding Royalty Interests, dated as of November 16, 2011, by and between Chesapeake E&amp;P Holding Corporation and Chesapeake Granite Wash Trust.</p>	8-K	001-35343	10.5	11/21/2011	10.5
<p>Administrative Services Agreement, dated as of</p>					
<p>November 16, 2011, by and between Chesapeake Energy Corporation and Chesapeake Granite Wash Trust.</p>	8-K	001-35343	10.6	11/21/2011	10.6

Table of Contents

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10.7	Development Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.7	11/21/2011	
10.8	Drilling Support Mortgage, dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.8	11/21/2011	
10.9	Registration Rights Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.9	11/21/2011	
10.10	Derivative Contract, dated as of November 16, 2011, by and between Morgan Stanley Capital Group Inc. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.10	11/21/2011	
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 - Trustee's Vice President.					X
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 - Trustee's Vice President					X
99.1	Report of Ryder Scott Company, L.P.					X

Table of Contents

SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the registrant has duly caused this report to be signed on its behalf by the undersigned thereunto duly authorized.

Date: March 15, 2013

CHESAPEAKE GRANITE WASH TRUST

By: THE BANK OF NEW YORK MELLON  
TRUST COMPANY, N.A, Trustee

By: /s/ Michael J. Ulrich  
Michael J. Ulrich  
Vice President

The registrant, Chesapeake Granite Wash Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available, and none have been provided. In signing the report above, the Trustee does not imply that it has performed any such function or that such function exists pursuant to the terms of the Trust Agreement under which it serves.

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Table of Contents

## EXHIBIT INDEX

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Table of Contents

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