CHESAPEAKE GRANITE WASH TRUST
Form 10-Q
December 22, 2011
**Table of Contents**

# UNITED STATES

# SECURITIES AND EXCHANGE COMMISSION

**Washington, D.C. 20549**

# FORM 10-Q

x **Quarterly Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934**
**For the Quarterly Period Ended September 30, 2011**

¨ **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)** |

**(800) 852-1422**

**(Registrant s telephone number, including area code)**

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 x

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

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

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

As of December 21, 2011, 35,062,500 Common Units and 11,687,500 Subordinated Units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding.

**Table of Contents**

**CHESAPEAKE GRANITE WASH TRUST**

**INDEX TO FORM 10-Q FOR THE QUARTER ENDED SEPTEMBER 30, 2011**



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.

**Table of Contents**

## DISCLOSURES REGARDING FORWARD-LOOKING STATEMENTS

This Quarterly Report on Form 10-Q ( Quarterly Report ) includes forward-looking statements about the Trust and Chesapeake and other matters discussed herein that are subject to risks and uncertainties within the meaning of Section 27A of the Securities Act of 1933, as amended, 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 Management s Discussion and Analysis of Financial Condition and Results of Operations in Item 2 of Part I and Risk Factors in Item 1A of Part II and elsewhere herein regarding the proved oil and natural gas reserves associated with the properties underlying the Royalty Interests, the Trust s or Chesapeake s future financial position, business strategy, budgets, project 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, anticipat potential, could, may, foresee, plan, goal, should, intend or other words that convey the uncertainty of future events or outcomes. T forward-looking statements are based on current expectations and assumptions about future events. These statements are based on certain assumptions made by us, 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 II of this Quarterly 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 Trust undertakes no obligation to publicly update or revise any forward-looking statements.

Table of Contents

## PART I. FINANCIAL INFORMATION

**ITEM I.** ***Financial Statement***

### CHESAPEAKE GRANITE WASH TRUST

### STATEMENT OF ASSETS AND TRUST CORPUS

| | September 30, 2011 (Unaudited) |
|---|---|
| **ASSETS:** | |
| Cash | $ 1,000 |
| **TOTAL ASSETS** | $ 1,000 |
| **TRUST CORPUS:** | |
| Trust corpus | $ 1,000 |
| **TOTAL TRUST CORPUS** | $ 1,000 |

The accompanying notes are an integral part of this financial statement.

Table of Contents

**CHESAPEAKE GRANITE WASH TRUST**

**NOTES TO FINANCIAL STATEMENT**

**(Unaudited)**

**1. Organization of Trust**

Chesapeake Granite Wash Trust is a statutory trust formed on June 29, 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 was created to acquire and hold 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.LC., 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 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 ) to be drilled on properties within an area of mutual interest ( AMI ). Pursuant to a development agreement with the Trust, Chesapeake intends to drill, or cause to be drilled, the 118 Development Wells by June 30, 2015 and is obligated to complete such drilling by June 30, 2016. Chesapeake has retained an interest in each of the Producing Wells and Development Wells and expects to operate a substantial number of the Producing Wells and 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 hedging arrangements between the Trust and its counterparty. The Royalty Interests entitle the Trust to receive 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sale of production of oil, natural gas liquids 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 sale of oil, natural gas liquids and natural gas production attributable to Chesapeake s net revenue interest in the Development Wells beginning on the effective date of the conveyances of the Royalty Interests, July 1, 2011.

Neither the Trust nor the Trustee is responsible for, or has any control over, any costs related to the drilling of the Development Wells or any other operating or capital costs of the Underlying Properties. The Trust s cash receipts with respect to the Royalty Interests in the Underlying Properties are determined after deducting certain post-production expenses and any applicable taxes associated with the Royalty Interests. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas liquids and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by Chesapeake. The Trust s distributable income will be adjusted to account for derivative settlements as discussed further in Note 6 under Hedging Arrangements , and will be reduced by the Trust s general and administrative expenses.

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.

Table of Contents

**CHESAPEAKE GRANITE WASH TRUST**

**NOTES TO FINANCIAL STATEMENT CONTINUED**

**(Unaudited)**

**2. Basis of Presentation and Summary of 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 Securities and Exchange Commission ( SEC ) as specified by Staff Accounting Bulletin Topic 12:E, *Financial Statements of Royalty Trusts.*

The accompanying financial statement as of September 30, 2011 has been prepared by the Trust in accordance with the accounting policies noted below. The accompanying unaudited interim financial statement should be read in conjunction with the December 31, 2010 audited financial statements and notes thereto included in the final prospectus (the Prospectus ) filed with the SEC on November 14, 2011 by the Trust pursuant to Rule 424(b) under the Securities Act of 1933.

*Significant Accounting Policies*. 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.

*Cash*. Cash equivalents include all highly liquid instruments with maturities of three months or less at the time of acquisition.

*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 will be 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 significant revisions are known.

On a quarterly basis, the Trust will evaluate 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.

*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 impairment of Investment in Royalty Interests. Actual results could differ from those estimates.

*Derivative Financial Instruments.* To mitigate a portion of the exposure to adverse market changes of oil and natural gas liquids prices, the Trust is party to hedging arrangements with its hedge counterparty. See Note 6 under Hedging Arrangements for discussion of the derivative contracts currently outstanding.

3

**CHESAPEAKE GRANITE WASH TRUST**

**NOTES TO FINANCIAL STATEMENT CONTINUED**

**(Unaudited)**

The Trust will record gains or losses from the derivative contracts conveyed under the hedging arrangements when proceeds are received or payments are made, respectively. Additionally, changes in the fair value of the derivative contracts will be 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.

**3. Income Taxes**

The Trust is a Delaware statutory trust that is treated as a partnership for federal income tax purposes. The Trust is not required to pay federal or state income taxes.

Trust unitholders will be 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.

**4. Distributions to Unitholders**

The Trust will make quarterly cash distributions 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. The first distribution, which will cover production for July and August 2011, is expected to be made on December 28, 2011 to record unitholders as of December 15, 2011. The Trustee intends to withhold $1.0 million from the first distribution to establish an initial cash reserve available for future Trust expenses. The Trust expenses expected to be incurred and paid before the third quarter distribution in December 2011 are approximately $0.3 million. Distributions to unitholders are recorded when paid. See Note 6 for discussion of the first distribution.

**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, which may be adjusted for inflation by no more than 3% in any calendar year, beginning in 2015. The Trust will also pay, out of the first cash payment received by the Trust, the Trustee s and the Delaware Trustee s legal expenses incurred in forming the Trust as well as the Trustee s acceptance fee in the amount of $10,000. There were no amounts paid to the Trustee for administrative fees prior to October 1, 2011.

*Agreements with Chesapeake.* The Trust entered into a registration rights agreement, a development agreement and an administrative service agreement with Chesapeake on November 16, 2011. See Note 6.

*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 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 September 30, 2011, there were no such loans outstanding with Chesapeake.

4

Table of Contents

**CHESAPEAKE GRANITE WASH TRUST**

**NOTES TO FINANCIAL STATEMENT    CONTINUED**

**(Unaudited)**

**6. Subsequent Events**

*Public Offering of Common Units and Issuance of Subordinated Units.* 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, including 3,000,000 common units sold pursuant to the option to purchase additional units exercised by the underwriters, for cash proceeds of approximately $409.7 million, net of $27.3 million in underwriting and structuring fees. 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 (  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 (  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 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.

*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. Pursuant to the registration rights agreement, the Trust agreed to register the Trust units held by Chesapeake and certain of its affiliates and permitted transferees upon request by Chesapeake. The holders of the registrable securities are entitled to demand a maximum of five such registrations.

*Conveyance of Royalty Interests.* Concurrent with the public offering, Chesapeake conveyed the Royalty Interests, as described in Note 1, to the Trust at the historical cost of the Royalty Interests. The historical cost to Chesapeake will be 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.

The Royalty Interests entitle the Trust to receive 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sale of production of oil, natural gas liquids 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 sale of oil, natural gas liquids and natural gas production attributable to Chesapeake  s net revenue interest in the Development Wells beginning on the effective date of the conveyances of the Royalty Interests, July 1, 2011.

5

Table of Contents

**CHESAPEAKE GRANITE WASH TRUST**

**NOTES TO FINANCIAL STATEMENT CONTINUED**

**(Unaudited)**

*Development Agreement*. On November 16, 2011, the Trust entered into a development agreement with Chesapeake, effective July 1, 2011, that obligates Chesapeake to drill, or cause to be drilled, the Development Wells by June 30, 2015. In the event of delays, Chesapeake will have until June 30, 2016 to fulfill its drilling obligation. Additionally, 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 until Chesapeake has met its obligation to drill the Development Wells. A wholly owned subsidiary of Chesapeake has granted to the Trust a lien covering Chesapeake s retained interest in the AMI (except its interest in the Producing 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 ( Drilling Support Lien ). The maximum amount that may be obtained by the Trust pursuant to the Drilling Support Lien may 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. As of September 30, 2011, 5.5 Development Wells as calculated under the development agreement had been drilled and completed and the maximum amount recoverable under the Drilling Support Lien had been reduced to approximately $250.4 million.

*Administrative Services Agreement*. On November 16, 2011, the Trust entered into an administrative services agreement with Chesapeake, effective July 1, 2011, that obligates the Trust to pay Chesapeake an annual administrative services fee for accounting, tax preparation, bookkeeping and informational services to be performed by Chesapeake on behalf of the Trust. The annual fee of $200,000 is payable in equal quarterly installments and 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 Trust s Royalty Interests over the periods hedged. However, in fulfilling its role as hedge manager, Chesapeake will not act as a fiduciary for the Trust and will have no affirmative duty to modify any of the Trust s derivative contracts, except as required by the hedging arrangements and the administrative services agreement. Moreover, Chesapeake will be 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 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.

*Hedging Arrangements.* On November 16, 2011, Chesapeake novated to the Trust the derivative contracts described in the table below, and the Trust became party to hedging arrangements covering a portion of the Trust s oil and natural gas liquids production from October 1, 2011 thorough September 30, 2015. These commodity derivative contracts consist of fixed-price swaps, in which the Trust receives a fixed-price and pays a floating market price to the counterparty for the hedged commodity. 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. Settlements are due on a quarterly basis, including the first two

Table of Contents

**CHESAPEAKE GRANITE WASH TRUST**

**NOTES TO FINANCIAL STATEMENT CONTINUED**

**(Unaudited)**

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 first settlement date for the Trust s derivative contracts will be on or about February 7, 2012.

The following table presents the production volumes hedged and weighted average prices to be received by the Trust with respect to the fixed-price swap contracts underlying the hedging arrangements:

| | Oil | | Natural Gas Liquids | |
|---|---|---|---|---|
| **Production Quarter** | **Volume (mbbl)** | **Weighted Avg. Price (per bbl)** | **Volume (mbbl)** | **Weighted Avg. Price (per bbl)** |
| Q4 2011 | 89.7 | $ 84.37 | 150.1 | $ 41.50 |
| Q1 2012 | 89.2 | 84.99 | 151.4 | 41.80 |
| Q2 2012 | 91.4 | 85.71 | 153.4 | 42.16 |
| Q3 2012 | 97.2 | 86.40 | 161.5 | 42.50 |
| Q4 2012 | 102.3 | 86.98 | 169.1 | 42.79 |
| Q1 2013 | 99.4 | 87.37 | 168.3 | 42.98 |
| Q2 2013 | 101.1 | 87.60 | 169.0 | 43.09 |
| Q3 2013 | 104.1 | 87.79 | 170.5 | 43.18 |
| Q4 2013 | 101.6 | 87.99 | 167.8 | 43.28 |
| Q1 2014 | 97.7 | 88.08 | 167.1 | 43.33 |
| Q2 2014 | 96.3 | 88.21 | 170.8 | 43.39 |
| Q3 2014 | 97.1 | 88.34 | 166.0 | 43.46 |
| Q4 2014 | 95.0 | 88.45 | 161.1 | 43.51 |
| Q1 2015 | 92.5 | 88.59 | 159.7 | 43.58 |
| Q2 2015 | 95.3 | 88.76 | 162.9 | 43.66 |
| Q3 2015 | 80.6 | 88.90 | 148.5 | 43.73 |
| Total | 1,530.5 | 87.42 | 2,597.2 | 43.01 |

The obligations to the counterparty under the hedging arrangements are secured by the Royalty Interests. The value of the novated hedges as of the date of novation, November 16, 2011, was a liability of $21.0 million.

*Initial Cash Distribution.* On December 5, 2011, the Trust declared a cash distribution of $0.58 per unit covering production for the period from July 1, 2011 to August 31, 2011 for record holders as of December 15, 2011. The distribution will be paid on December 28, 2011. Distributable income for production from July 1, 2011 to August 31, 2011 was calculated as follows (in thousands, except for unit and per unit amounts):

| | |
|---|---|
| **Revenues** | |
| Royalty income[(1)] | $ 29,334 |
| Total Revenues | $ 29,334 |
| **Expenses** | |
| Production taxes | 906 |
| Trust administrative expenses | 256 |
| Cash reserves withheld by Trustee | 1,000 |

| | |
|---|---|
| Total Expenses | 2,162 |
| Distributable income available to unitholders | $ 27,172 |
| | |
| Distributable income per unit (46,750,000 units issued and outstanding) | $ 0.58 |

(1) Net of certain post-production expenses.

Table of Contents

**ITEM 2.** ***Management 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 Trust s financial statement and the accompanying notes included in this Quarterly Report, the Trust s audited financial statements and the accompanying notes included in the Prospectus, filed November 14, 2011, related to the Trust s initial public offering (the Prospectus ) and the Discussion and Analysis of Historical Results from the Producing Wells beginning on page 68 of the Prospectus. Capitalized items in this Item 2 have the same meanings ascribed to them in Note 1 to the Trust s financial statement included in this Quarterly Report.

**Overview**

The Trust is a statutory trust created under the Delaware Statutory Trust Act in June 2011. 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 hedging arrangements (described in Note 6 to the financial statement contained in Part I, Item 1 of this Quarterly 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 hedging arrangements. 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 to the Trust of the Royalty Interests.

Concurrent with the initial public offering, Chesapeake conveyed to the Trust, effective July 1, 2011, Royalty Interests that included interests in (a) 69 Producing Wells in the Colony Granite Wash play and (b) 118 Development Wells to be drilled in the Colony Granite Wash play on properties within the AMI. Chesapeake intends to drill, or cause to be drilled, the Development Wells from drill sites on the acreage in the AMI between July 1, 2011 and June 30, 2015 and is obligated to complete such drilling by June 30, 2016. As of September 30, 2011, 5.5 Development Wells as calculated under the development agreement had been drilled and completed.

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 will not be 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 sale of production of oil, natural gas liquids 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 sale of oil, natural gas liquids and natural gas production attributable to Chesapeake s net revenue interest in the Development Wells beginning on the effective date of the conveyances of the Royalty Interests, July 1, 2011. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas liquids and natural gas produced. However, the Trust is not responsible for costs of marketing services provided by Chesapeake.

On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering a portion of the oil and natural gas liquids 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 commodity derivative contracts. The value of the novated hedges as of the date of novation was a liability of $21.0 million.

**Table of Contents**

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 first distribution, consisting of proceeds attributable to July and August 2011 production, will be made on December 28, 2011 to record unitholders as of December 15, 2011. The Trustee will withhold $1.0 million from the first distribution to establish an initial cash reserve available for Trust expenses.

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

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

*Subordination Threshold.* In order to provide support for cash distributions on the common units, 11,687,500 units (25% of the outstanding Trust units) are subordinated units. The subordinated units, which are owned by Chesapeake, 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 not less than the applicable subordination threshold for the corresponding quarter as set forth in the Trust Agreement and as shown in the table below. If there is not sufficient cash to fund such a distribution on all of the common units (including the common units Chesapeake owns), 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, up to the subordination threshold amount on all the common units (including the common units held by Chesapeake).

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

At the end of the 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 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. There is no assurance of any minimum distribution at any time.

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 set out in the Trust Agreement:

| Period | Subordination Threshold[1] | Incentive Threshold[1] |
|---|---|---|
| **2011:** | | |
| Third Quarter[2] | $ 0.43 | $ 0.65 |
| Fourth Quarter | 0.54 | 0.82 |
| **2012:** | | |
| First Quarter | 0.59 | 0.89 |
| Second Quarter | 0.61 | 0.91 |
| Third Quarter | 0.63 | 0.94 |
| Fourth Quarter | 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 fourth full calendar quarter following Chesapeake s completion of its drilling obligation (2) Includes proceeds attributable to the first two months of actual production from July 1, 2011 to August 31, 2011, and gives effect to the establishment of $1.0 million of reserves for expenses withheld by the Trustee. Actual distribution for this period was $0.58 per unit.

10

Table of Contents

**Results of Trust Operations**

The Trust completed its initial public offering in November 2011 and did not receive or disburse any funds during the three months ended September 30, 2011. On December 5, 2011, the Trust declared a cash distribution of $0.58 per unit covering production for the period from July 1, 2011 to August 31, 2011 to record unitholders as of December 15, 2011. The distribution will be paid on December 28, 2011. Distributable income from July 1, 2011 to August 31, 2011 production was calculated as follows (in thousands except for unit and per unit amounts):

| | |
|---|---|
| **Revenues** | |
| Royalty income[(1)] | $ 29,334 |
| Total Revenues | $ 29,334 |
| **Expenses** | |
| Production taxes | 906 |
| Trust administrative expenses | 256 |
| Cash reserves withheld by Trustee | 1,000 |
| Total Expenses | 2,162 |
| Distributable income available to unitholders | $ 27,172 |
| | |
| Distributable income per unit (46,750,000 units issued and outstanding) | $ 0.58 |

(1) Net of certain post-production expenses.

*Royalty Income.* Royalty income received during the two-month period ended August 31, 2011 totaled $29.3 million based upon sales of production attributable to the Royalty Interests of 133 thousand barrels ( mbbls ) of oil, 225 mbbls of natural gas liquids and 2,172 million cubic feet ( mmcf ) of natural gas. Total production for the two-month period was 720 thousand barrels of oil equivalent ( mboe ). Average prices received for oil, natural gas liquids and natural gas production, including the impact of certain post-production expenses and excluding production tax, during the two-month period ended August 31, 2011 were $88.26 per barrel ( bbl ), $46.65 per bbl and $3.26 per thousand cubic feet ( mcf ), respectively. Average sales prices are net of certain post-production expenses, including gathering, storage, compression, transportation, processing, treating, dehydrating and non-affiliate marketing expenses.

*Production Taxes.* Production taxes are calculated as a percentage of oil, natural gas liquids and natural gas revenues, net of any applicable tax credits. Production taxes for the two-month period ended August 31, 2011 totaled $0.9 million, or $1.26 per barrel of oil equivalent ( boe ), and were approximately 3% of royalty income.

*Distributable Income.* Distributable income for the two-month period ended August 31, 2011 was $27.2 million, which included a $1.3 million reduction for Trust administrative expenses and to establish an initial cash reserve for the payment of future Trust administrative expenses.

Distributable income of $0.58 per unit for the period from July 1, 2011 to August 31, 2011 was higher than the estimated distribution of $0.54 per unit as stated in the Prospectus primarily as a result of higher than anticipated prices for all three commodities. The average price received for oil sales of $88.26 per bbl for July 1, 2011 to August 31, 2011 production exceeded the price of $87.94 per bbl assumed in preparing the target distribution level for the same period. The average price received for natural gas liquids sales of $46.65 per bbl exceeded the price of $42.66 per bbl assumed in preparing the target distribution level for the same period. The average price received for natural gas sales of $3.26 per mcf for July 1, 2011 to August 31, 2011 production exceeded the price of $3.12 per mcf assumed in preparing the target distribution level for the same period.

In addition, production related to the Royalty Interests for September 2011 was 64 mbbls of oil, 94 mbbls of natural gas liquids and 1,070 mmcf of natural gas, increasing total quarterly production by 337 mboe to total production of 1,057 mboe.

Table of Contents

*Development Wells*. As of September 30, 2011, all of the 69 Producing Wells and 5.5 Development Wells as calculated under the development agreement were completed and producing.

**Liquidity and Capital Resources**

The Trust s principal sources of liquidity and capital are cash flows generated from the Royalty Interests, the hedging arrangements and the loan commitment described in Note 5 to the financial statement contained in Part I, Item I of this Quarterly Report. The Trust s primary uses of cash are distributions to Trust unitholders, including, if applicable, incentive distributions to Chesapeake, payment of Trust administrative expenses, including any reserves established by the Trustee for future liabilities, payments for derivative contract settlements and payment of expense reimbursements to Chesapeake for out-of-pocket expenses incurred 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 sale of oil, natural gas liquids 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 above.

**Critical Accounting Policies and Estimates**

Refer to Note 2 to the financial statement contained in Part I, Item I of this Quarterly Report for a description of the Trust s accounting policies and use of estimates.

**ITEM 3. *Quantitative and Qualitative Disclosures about Market Risk***

The discussion in this section provides information about commodity derivative contracts pursuant to hedging arrangements between the Trust and its counterparty effective October 1, 2011. The contracts underlying the hedging arrangements cover a portion of the expected volumes of oil and natural gas liquids production through September 30, 2015, including a portion of the production attributable to the Royalty Interests from the Producing Wells as well as a portion of the future production from the Development Wells. The commodity derivative contracts are to be settled in cash and do not require the actual delivery of a commodity at settlement. The contracts will be settled based upon New York Mercantile Exchange ( NYMEX ) prices. Under the hedging arrangements, the Trust will receive 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 commodity derivative contracts, except in limited circumstances. See Note 6 to the financial statement contained in Part I, Item I of this report for a description of the Trust s open oil and natural gas liquids commodity derivative contracts.

*Commodity 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, natural gas liquids and natural gas from the Underlying Properties. The Trust is significantly exposed to fluctuations in the prices received for oil, natural gas liquids and natural gas produced and sold. The derivative contracts described above are designed to mitigate a portion of the variability of oil and natural gas liquids prices received for the Trust s share of production.

*Credit Risk.* A portion of the Trust s liquidity is concentrated in the derivative contracts described above. The use of derivative contracts exposes the Trust to credit risk from its counterparty, which has an investment grade credit rating. The Trust does not have the ability to enter into any additional derivative contracts, except in limited circumstances.

**ITEM 4. *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. As of the end of the period covered by this Quarterly Report, the Trustee carried out an evaluation of the Trustee s disclosure controls and procedures. Mike 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 and (iii) 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.

During the quarter ended September 30, 2011, the Trustee established its policies and procedures relating to internal control over financial reporting relating to the Trust. Except for the establishment of these policies and procedures, 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.

Table of Contents

## PART II. OTHER INFORMATION

**ITEM 1A.** ***Risk Factors***

**Risks Related to the Units**

***Drilling for and producing oil, natural gas liquids 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, natural gas liquids and natural gas production. Drilling for oil, natural gas liquids 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. The costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures could cause Chesapeake to re-direct its drilling capital to other plays and delay the drilling of the Development Wells beyond what was assumed in establishing target levels of cash distributions to unitholders. 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, natural gas liquids and natural gas water or drilling fluids;

natural disasters;

environmental hazards, such as oil, natural gas liquids 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, natural gas liquids and natural gas prices or, for hedged production, increases in pricing differentials; and

title problems affecting the Underlying Properties.

**Table of Contents**

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 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, natural gas liquids 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 sale of oil, natural gas liquids and natural gas. The markets for these commodities are very volatile. Oil, natural gas liquids 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, natural gas liquids and natural gas;

the price and level of foreign imports of oil, natural gas liquids 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, natural gas liquids and natural gas;

weather conditions and seasonal trends;

anticipated future prices of oil, natural gas liquids, 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;

- the level and effect of trading in commodity futures markets, including by commodity price speculators and others; 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 December 16, 2011, 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 December 16, 2011, the highest monthly NYMEX settled price was $13.11 per mmbtu and the lowest was $2.84 per mmbtu. In addition, the market price of oil, natural gas liquids and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil, natural gas liquids and natural gas for heating purposes during the winter season.

Lower oil, natural gas liquids and natural gas prices will reduce proceeds to which the Trust is entitled and may ultimately reduce the amount of oil, natural gas liquids 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, natural gas liquids and natural gas prices to shut in or curtail production from wells on the Underlying Properties. In addition, the operator of the

Table of Contents

Underlying Properties could determine during periods of low oil, natural gas liquids 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, natural gas liquids 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, natural gas liquids and natural gas prices also reduces the accuracy of target distributions to Trust unitholders. There can be no assurance that the Trust s hedging program will mitigate these risks.

***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 Trust s 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, natural gas liquids and natural gas in an exact way and estimating reserves is inherently uncertain. 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, natural gas liquids and natural gas based on factors and assumptions that include:

- historical production from the area compared with production rates from other producing areas;
- oil, natural gas liquids and natural gas prices, production levels, btu content, production expenses, transportation costs, severance 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

***Estimates of the target distributions to unitholders, 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 to unitholders, subordination thresholds and incentive thresholds, as set forth in the Prospectus and in this Quarterly Report, have been established by Chesapeake, and Chesapeake has not received an opinion or report on such calculations from any independent accountants, financial advisers or engineers. Such estimates are based on assumptions about drilling, production, oil, natural gas liquids 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, natural gas liquids and natural gas production is sold at prices consistent with spot and settled NYMEX pricing for July through October 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 recently. 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; 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, natural gas liquids 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, natural gas liquids and natural gas differ from the assumptions used to generate the target distributions, the actual distributions you 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 (which is 20% below the target distribution level for the corresponding 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 will be 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 set forth in the Prospectus and in this Quarterly Report 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, or cause to be drilled, 118 Development Wells in the AMI. Chesapeake owns a majority working interest in approximately 93% of 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 certain of these 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 servicers 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, natural gas liquids 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, natural gas liquids 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, natural gas liquids and natural gas on the Underlying Properties could be materially and adversely affected by severe or unseasonable weather.***

Production of oil, natural gas liquids 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 gas industry can fluctuate significantly, often in correlation with oil, natural gas liquids 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, natural gas liquids 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.

***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 will be operated for oil, natural gas liquids and natural gas production only and are focused exclusively in the Colony Granite Wash in Washita County in western Oklahoma. This concentration could disproportionately expose the Trust s interests to operational and regulatory risk in that area. Due to the lack of diversification in industry type and location of the Trust s interests, adverse developments in the oil, natural gas

18

liquids 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 Trust s Royalty Interests were more diversified.

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

The amount of oil, natural gas liquids 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, natural gas liquids 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.

***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, sale of oil, natural gas liquids 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 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, sale of oil, natural gas liquids and natural gas from, or future development of, the Underlying Properties.

***The oil, natural gas liquids 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 gas properties or royalty interests to replace the depleting assets and production.***

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

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

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

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

- the Trust s share of applicable taxes on the oil, natural gas liquids 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 hedging arrangements.

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 hedging arrangements for the Trust will cover only a portion of the production attributable to the Trust, such arrangements will limit the Trust s ability to benefit from commodity price increases for hedged volumes, and such arrangements will be secured by the Trust s Royalty Interests in the Underlying Properties and may require the Trust to make cash payments in excess of its receipts.***

The Trust is party to oil and natural gas liquids hedging arrangements pursuant to which the Trust hedged approximately 50% of the expected oil and natural gas liquids production and 37% of the Trust s expected revenues (based on NYMEX strip oil prices as of October 28, 2011) upon which the target distributions from October 1, 2011 through September 30, 2015 are based. Estimated production of natural gas liquids will be hedged using a conversion ratio of one barrel of natural gas liquids to 49.2% of a barrel of oil, which ratio may not be consistent with the market conversion ratio in the future. Except in limited circumstances involving the restructuring of an existing derivative contracts, the remaining estimated production of oil and natural gas liquids 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 commodity 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, natural gas liquids and natural gas, commodities that are frequently characterized by significant price volatility. Furthermore, while the use of hedging arrangements limits the downside risk of price declines, they may also limit the Trust s ability to benefit from increases in oil and natural gas liquids prices above the hedge price on the portion of the production attributable to the Trust s 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 will not act as a fiduciary for the Trust, will have no affirmative duty to modify any of the Trust s hedges except as required by the hedging arrangements, and will have no liability to the Trust in connection with Chesapeake s failure to modify, or any affirmative modification of, any of the 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 Trust s hedging arrangements depends upon the financial position of the counterparty. If the counterparty to the oil and natural gas liquids hedging arrangements 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 natural gas liquids prices.

If actual production, over which the Trust has no control, is below the amounts forecast in the reserve reports and oil or natural gas liquids prices rise, the hedging arrangements entered into by the Trust may result in the Trust having to make cash payments under the hedging arrangements 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 Trust s Royalty Interests is insufficient to cover the volume of production specified in the applicable hedging arrangements. Accordingly, if the production attributable to the Trust s 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 hedging arrangements 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 if the hedging arrangements. 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 hedging arrangements 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 hedging arrangements will be secured by the Trust s Royalty Interests in the Underlying Properties. 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 hedging arrangements, 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 Trust s Royalty Interests in the Underlying Properties. 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 hedging arrangements 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.

Table of Contents

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

The Royalty Interests will be sold and the Trust will be dissolved upon the occurrence of certain events. For example, the Trustee must sell the Royalty Interests if unitholders approve the sale or vote to dissolve the Trust. The Trustee must also sell the Royalty Interests if cash available for distribution is less than $1.0 million in each of any four consecutive quarters. The sale of all of the Royalty Interests will result in the dissolution of the Trust. Upon the dissolution of the Trust, the net proceeds of any such sale, after the payment of Trust liabilities, will be distributed to the Trust unitholders pro rata and unitholders will not be entitled to receive any proceeds from the sale of production from the Underlying Properties following such date. If none of these events occur, the Trust will dissolve on the Termination Date.

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

Table of Contents

***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 has agreed not to sell any Trust units until May 8, 2012 without the consent of Morgan Stanley & Co. LLC and Raymond James & Associates, Inc. After such 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 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, natural gas liquids 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 Midstream Partners provides Chesapeake with gathering, treatment and compression services with respect to natural gas and Chesapeake Midstream Development provides Chesapeake with gathering services with respect to oil in the Colony Granite Wash. These Chesapeake affiliates are expected to provide these services with respect to substantially all of the Underlying Properties. The amounts charged by Chesapeake Midstream Partners and Chesapeake Midstream Development are post-production expenses that are deducted from Trust revenues before making distributions to Trust unitholders. Chesapeake could favor the interests of these affiliates to the detriment of the Trust and Trust unitholders.

After expiration of a 180-day lock-up period, 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, natural gas liquids 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 Trust s Royalty Interests. Any purchaser, farmout counterparty or participating partner could have a weaker financial position and/or be less experienced in oil, natural gas liquids 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 Interest will not burden any interests that the counterparty earns under such an agreement.

***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, or cause to be drilled, the Development Wells at its own expense. Chesapeake expects to operate approximately 93% of such wells until the completion of its drilling obligation. Chesapeake also currently operates 94% of the Producing Wells. The conveyances provide that Chesapeake is obligated to market, or cause to be marketed, the oil, natural gas liquids 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 Trust s 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 and economic performance and access to capital, which in turn will depend upon the supply and demand for oil, natural gas liquids 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 $262.7 million, which is the estimated amount of the Trust s share of the costs of drilling the 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 Interest 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 Trust s 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 Trust s 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. 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, natural gas liquids 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 will convey 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 will convey 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.

***Oil and gas drilling and producing operations can be hazardous and may expose Chesapeake to liabilities, including environmental liabilities.***

Oil and 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 environmental hazards and risks. Chesapeake s drilling operations involve risks from high pressures and from mechanical difficulties such as stuck pipes, collapsed casings and separated cables. 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 sale of oil, natural gas liquids 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 gas operations due to the generation, handling and disposal of materials, including wastes and petroleum hydrocarbons. 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 natural gas and oil exploration and production activities for a number of years, often by third parties not under its control. 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, we are 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 will have no insurance or indemnification to protect against losses or delays in receiving proceeds from such events.

***Potential legislative and regulatory actions could increase Chesapeake s costs, reduce its revenue and cash flow from the sale of oil, natural gas liquids 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 Producers of Oil and Natural Gas*

Federal budget proposals would potentially increase and accelerate the payment of federal income taxes of 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 lengthen 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 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 increasing the transparency and stability of the over-the-counter ( OTC ) derivative markets and preventing excessive speculation. The Trust will engage in hedging activities to manage the risk of low commodity prices and to predict with greater certainty the cash flow from its hedged production. The Dodd-Frank Act and the rules and regulations promulgated thereunder could reduce trading positions in the energy futures markets. Such changes could materially reduce hedging opportunities for the Trust and negatively affect its revenues and cash flow during periods of low commodity prices.

*Hydraulic Fracturing*

Hydraulic fracturing, the process of creating or expanding cracks, or fractures, in formations underground where water, sand and other additives are pumped under high pressure into the formation, is currently used in completing greater than 90% of all oil and natural gas wells drilled in the United States. While hydraulic fracturing is typically regulated by state oil and gas commissions, 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 begun the process of drafting guidance documents for permitting authorities and the industry on the process for obtaining a permit for hydraulic fracturing involving diesel fuel. At the same time, the EPA has commenced a study of the potential environmental impacts of hydraulic fracturing activities, with results of the study anticipated to be available by late 2012. Also, for the second consecutive session, legislation has been introduced in Congress to provide for federal regulation of hydraulic fracturing and to require disclosure of the chemicals used in the fracturing process. Chesapeake cannot predict whether additional hydraulic fracturing federal, state or local laws or regulations will be enacted 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, Chesapeake s operations with respect to the Underlying Properties could be subject to delays, increased operating and compliance costs and process prohibitions. Restrictions on hydraulic fracturing could also reduce the amount of oil, natural gas liquids and natural gas that Chesapeake is ultimately able to produce in commercial quantities from the Underlying Properties.

*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 findings and issued regulations that require Chesapeake to establish and report an inventory of greenhouse gas emissions and that could lead to the imposition of restrictions on greenhouse gas emissions from stationary sources used in oil and gas operations. 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, natural gas liquids 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 greenhouse gas emissions, pay taxes related to our 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, natural gas liquids 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.

Table of Contents

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 you would generally be taxed again as corporate distributions, and no income, gains, losses, deductions or credits would flow through to you 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 you 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 income tax purposes, the minimum quarterly distribution amount 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 Royalty Interest in Development Wells is not entirely free from doubt. A successful challenge by the IRS to the tax position the Trust takes with respect to the Royalty Interest in Development Wells 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 Royalty Interest in Development Wells is not entirely free from doubt. A successful challenge by the IRS to the tax position the Trust takes with respect to the Royalty Interest in Development Wells 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.***

The Health Care and Education Reconciliation Act of 2010 includes a provision that, in taxable years beginning after December 31, 2012, subjects an individual having adjusted gross income in excess of $200,000 (or $250,000 for married taxpayers filing joint returns) to an additional Medicare tax equal generally to 3.8% of the lesser of such excess or the individual s net investment income, which 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, absent new legislation extending the current rates, beginning July 1, 2013, the highest marginal U.S. federal income tax rate applicable to ordinary income and long-term capital gains of individuals will increase to 39.6% and 20%, respectively. It has been assumed that the effective rate of production tax on the oil, natural gas liquids 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, at the federal level, legislation has been proposed in the past that would have eliminated partnership tax treatment for certain publicly traded partnerships. Although such legislation would not have applied to the Trust as it was proposed, it could be reintroduced in a manner that does apply to the Trust. Any such legislation would likely also affect the Trust tax treatment for state tax purposes.

***The Trust will adopt positions that may not conform to all aspects of existing Treasury Regulations. 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.***

If the IRS contests any of the U.S. federal income tax positions the Trust takes, the value of the Trust units may be adversely affected because 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. For example, the Trust will generally 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. Although simplifying conventions are contemplated by the Internal Revenue Code, and most publicly traded partnerships use similar simplifying conventions, the use of these methods may not be permitted under existing Treasury Regulations.

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 conclusions of the Trust s counsel expressed in the Prospectus or 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 conclusions of the Trust s counsel or the positions the Trust takes. A court may not agree with some or all of the conclusions of the Trust s counsel or 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.

***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.

Table of Contents

***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, accordingly, the Trust s counsel is unable to opine as to the validity of this method. 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.

Table of Contents

***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 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) for one calendar year. The IRS has recently 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, natural gas liquids 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 2012 is the elimination of certain key U.S. federal income tax preferences relating to oil, natural gas liquids 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.

**Table of Contents**

**ITEM 2.** ***Unregistered Sales of Equity Securities and Use of Proceeds***

**Use of Proceeds**

The Trust s initial public offering of common units of beneficial interest was effected through a Registration Statement on Form S-1 (File No. 333-175395), which was declared effective by the SEC on November 10, 2011 and registered an aggregate 20,000,000 common units that were sold at an initial public offering price of $19.00 per unit, for an aggregate gross offering price of $380.0 million. Morgan Stanley & Co. LLC and Raymond James & Associates, Inc. acted as representatives of the underwriters of the offering. Following the initial sale of the units, the underwriters exercised their option to purchase an additional 3,000,000 common units for $19.00 per unit, for additional gross proceeds of $57.0 million, resulting in total gross proceeds of $437.0 million, and the offering terminated.

The underwriting commissions (including a structuring fee payable to Morgan Stanley & Co. LLC and Raymond James & Associates, Inc.) totaled approximately $27.3 million in connection with the offering. The net offering proceeds to the Trust, after deducting commissions and offering costs, were approximately $409.7 million.

The Trust used all $409.7 million of the net proceeds to pay Chesapeake as partial consideration for the conveyance of the Royalty Interests. Chesapeake used the proceeds received from the sale of the Royalty Interests to the Trust to repay borrowings under Chesapeake s corporate credit facility. Chesapeake may re-borrow amounts under its credit facility from time to time and does so for general corporate purposes, including capital expenditures for land, drilling and other costs.

Table of Contents

**ITEM 6.** ***Exhibits***

The following exhibits are filed as a part of this report.

| | | Incorporated by Reference | | | | | |
|---|---|---|---|---|---|---|---|
| Exhibit Number | Exhibit Description | Form | SEC File Number | Exhibit | Filing Date | Filed Herewith | Furnished Herewith |
| 3.1 | Certificate of Trust of Chesapeake Granite Wash Trust. | S-1 | 333-175395 | 3.1 | 07/07/2011 | | |
| 3.2 | Amended and Restated Trust Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake 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 between Chesapeake Exploration, L.L.C. and Chesapeake E&P Holding Corporation. | 8-K | 001-35343 | 10.4 | 11/21/2011 | | |
| 10.5 | Assignment of Term Overriding Royalty Interests, dated as of November 16, 2011, by and between Chesapeake E&P Holding Corporation and Chesapeake Granite Wash Trust. | 8-K | 001-35343 | 10.5 | 11/21/2011 | | |
| 10.6 | Administrative Services Agreement, dated as of November 16, 2011, by and between Chesapeake Energy Corporation and Chesapeake Granite Wash Trust. | 8-K | 001-35343 | 10.6 | 11/21/2011 | | |

**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 | Hedge 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 | Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 Trustee s Vice President. | | | | | X | |
| 32 | Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 Trustee s Vice President | | | | | | 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: December 22, 2011

CHESAPEAKE GRANITE WASH TRUST

| | |
|---|---|
| By: | THE BANK OF NEW YORK MELLON TRUST COMPANY, N.A, Trustee |
| By: | /s/ Michael J. Ulrich |
| Name: | Michael J. Ulrich |
| Title: | 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.

**Table of Contents**

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