CHESAPEAKE GRANITE WASH TRUST
Form 10-Q
May 15, 2012
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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 March 31, 2012

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

Commission File No. 001-35343

Chesapeake Granite Wash Trust

(Exact name of registrant as specified in its charter)

Delaware **(State or other jurisdiction of** **incorporation or organization)**	**45-6355635** **(I.R.S. Employer** **Identification No.)**
The Bank of New York Mellon **Trust Company, N.A., Trustee** **Global Corporate Trust** **919 Congress Avenue** **Austin, Texas** **(Address of principal executive offices)**	**78701** **(Zip Code)**

(855) 802-1093

(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 x No ¨

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

Indicate by check mark 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 May 15, 2012, 35,062,500 Common Units and 11,687,500 Subordinated Units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding.

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CHESAPEAKE GRANITE WASH TRUST

INDEX TO FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2012

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

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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 that are intended to qualify for the safe harbor from liability established by the Private Securities Litigation Reform Act of 1995, and Section 21E of the Securities Exchange Act of 1934, as amended. All statements other than statements of historical fact included in this document, including, without limitation, statements under 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, anticipate, potential, could, may, foresee, plan, goal, assume, target, should, intend or other words that convey events or outcomes. These forward-looking statements are based on current expectations and assumptions about future events. These statements are based on certain assumptions made by the Trust, and by Chesapeake in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with such expectations and predictions is subject to a number of risks and uncertainties, including the risk factors discussed in Item 1A of Part I of the Trust s Annual Report on Form 10-K for the year ended December 31, 2011, and those set from time to time in the Trust s filings with the Securities and Exchange Commission, which could affect the future results of the energy industry in general, and the Trust and Chesapeake in particular, and could cause those results to differ materially from those expressed in such forward-looking statements. The actual results or developments anticipated may not be realized or, even if substantially realized, they may not have the expected consequences to or effects on Chesapeake s business and the Trust. Such statements are not guarantees of future performance and actual results or developments may differ materially from those projected in such forward-looking statements. The Trustee relies on Chesapeake for information regarding the Royalty Interests, the Underlying Properties and Chesapeake itself. The Trust undertakes no obligation to publicly update or revise any forward-looking statements.

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ITEM 1. Financial Statements

CHESAPEAKE GRANITE WASH TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

($ in thousands)

(Unaudited)

	March 31, 2012	December 31, 2011
ASSETS:		
Cash and cash equivalents	$ 1,130	$ 1,216
Investment in royalty interest	487,793	487,793
Less: accumulated amortization	(18,255)	(5,350)
Net investment in royalty interest	469,538	482,443
Total assets	$ 470,668	$ 483,659
LIABILITIES AND TRUST CORPUS:		
Loan from Chesapeake	$	$ 200
Short-term derivative liability	12,267	7,604
Total short-term liabilities	12,267	7,804
Long-term derivative liability	23,468	12,937
Trust corpus; 35,062,500 common units and 11,687,500 subordinated units authorized and outstanding	434,933	462,918
Total liabilities and trust corpus	$ 470,668	$ 483,659

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

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CHESAPEAKE GRANITE WASH TRUST

STATEMENT OF DISTRIBUTABLE INCOME

THREE MONTHS ENDED MARCH 31, 2012

($ in thousands, except per unit data)

(Unaudited)

REVENUES:	
Royalty income	$ 36,070
Interest income	1
Total Revenues	36,071
EXPENSES:	
Production taxes	752
Trust administrative expenses	362
Derivative settlement loss	824
Cash reserves withheld	114
Total Expenses	2,052
Distributable income	34,019
Distributable income per unit (46,750,000 units)	$ 0.7277

CHESAPEAKE GRANITE WASH TRUST

STATEMENT OF CHANGES IN TRUST CORPUS

THREE MONTHS ENDED MARCH 31, 2012

($ in thousands)

(Unaudited)

TRUST CORPUS: December 31, 2011	$ 462,918
Additional cash reserves	114
Amortization of investment in royalty interest	(12,905)
Change in derivative liability	(15,194)
Distributable income	34,019
Distributions paid to unitholders	(34,019)
TRUST CORPUS: March 31, 2012	$ 434,933

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

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CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS

(Unaudited)

1. Organization of the Trust

Chesapeake Granite Wash Trust (the Trust) is a statutory trust formed on June 29, 2011 by Chesapeake Energy Corporation (Chesapeake) under the Delaware Statutory Trust Act pursuant to an initial trust agreement by and among Chesapeake, as Trustor, The Bank of New York Mellon Trust Company, N.A., as Trustee (the Trustee), and The Corporation Trust Company, as Delaware Trustee (the Delaware Trustee).

The Trust was created to own royalty interests (the Royalty Interests) for the benefit of Trust unitholders pursuant to a trust agreement dated as of June 29, 2011 and subsequently amended and restated as of November 16, 2011 by and among Chesapeake, Chesapeake Exploration, L.L.C., a wholly owned subsidiary of Chesapeake, the Trustee and the Delaware Trustee (the Trust Agreement). The Royalty Interests are derived from Chesapeake s interests in specified oil and natural gas properties located in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma (the Underlying Properties). Chesapeake conveyed the Royalty Interests to the Trust from (a) Chesapeake s interests in 69 existing horizontal wells (the Producing Wells), and (b) Chesapeake s interests in 118 horizontal development wells (the Development Wells) that have been or that are to be drilled on properties held by Chesapeake within an area of mutual interest (the AMI) in Washita County in western Oklahoma. Pursuant to a development agreement with the Trust, Chesapeake intends to drill and complete, or cause to be drilled and completed, the 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 currently operates 95% of the Producing Wells and the completed Development Wells and expects to operate approximately 92% of the remaining Development Wells.

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

Through an initial public offering in November 2011, the Trust sold 23,000,000 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 GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

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.

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 affiliates of Chesapeake. Cash distributions to unitholders will be increased or decreased by the effect of the Trust s hedging arrangements related to oil and natural gas liquids production and reduced by the Trust s general and administrative expenses. See Hedging Arrangements in Note 3 below.

The Trust will dissolve and begin to liquidate on June 30, 2031, or earlier upon certain events (the Termination Date), and will soon thereafter wind up its affairs and terminate. At the Termination Date, (a) 50% of the total Royalty Interests conveyed by Chesapeake (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.

2. Basis of Presentation and Significant Accounting Policies

Basis of Accounting. The accompanying Statement of Assets, Liabilities and Trust Corpus as of December 31, 2011, which has been derived from audited financial statements, and the unaudited interim financial statements of the Trust as of March 31, 2012 and for the three month period ended March 31, 2012, have been presented in accordance with the rules and regulations of the Securities and Exchange Commission (SEC) and include all adjustments which are, in the opinion of the Trustee, necessary for a fair statement of the results for the interim periods presented. The accompanying unaudited interim financial statements should be read in conjunction with the December 31, 2011 audited financial statements and notes of the Trust included in the Trust s Annual Report on Form 10-K for the year ended December 31, 2011.

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

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

CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

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 and of the fair value of derivatives. Actual results could differ from those estimates.

Risk and Uncertainties. The Trust s revenue and distributions are substantially dependent upon the prevailing and future prices for oil, natural gas liquids and natural gas, each of which depends on numerous factors beyond the Trust s control such as economic conditions, regulatory developments and competition from other energy sources. Oil, natural gas liquids and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. The Trust s hedging arrangements serve to mitigate a portion of the effect of this price volatility. See Note 3 for the Trust s open commodity derivative contracts.

Chesapeake s ability to perform its obligations to the Trust 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 a drilling support lien (the Drilling Support Lien) to the extent of Chesapeake s remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the Trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation and the maximum amount the Trust can recover in a foreclosure or other action is limited to approximately $205.1 million as of May 10, 2012. The Drilling Support Lien will decrease as the remaining Development Wells are drilled and completed.

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

In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed the Royalty Interests to the Trust, the Trust could lose the value of all of the Royalty Interests if a bankruptcy court were to hold that the Royalty Interests constitute an asset of the bankruptcy estate. Chesapeake could also be unable to provide support to the Trust through loans and performance of its management duties.

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

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

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CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

This investment is amortized as a single cost center on a units-of-production basis over total proved reserves. Such amortization does not reduce distributable income, rather it is charged directly to 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 evaluates the carrying value of the Investment in Royalty Interests under the full cost accounting method prescribed by the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, the carrying value of the Investment in Royalty Interests may not exceed an amount equal to the sum of the present value (using a 10% discount rate) of the estimated future net revenues from proved reserves. Any write-downs resulting from the ceiling test will be non-cash charges to Trust corpus and will not affect distributable income.

Derivatives. To mitigate a portion of the exposure to adverse market changes of oil and natural gas liquids prices, the Trust is party to hedging arrangements with its hedge counterparty. See Note 3 for discussion of the derivative contracts currently outstanding.

The Trust records 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 are accounted for as an adjustment to Trust corpus and the fair value carried on the statement of assets, liabilities and trust corpus.

Loan Commitment. Pursuant to the Trust Agreement, if at any time the Trust s cash on hand (including available cash reserves) is not sufficient to pay the Trust s ordinary course expenses as they become due, Chesapeake will loan funds to the Trust necessary to pay such expenses. Such loans will be recorded as a liability on the statement of assets, liabilities and trust corpus until repaid. Loans neither increase or decrease distributions to unitholders, however, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid.

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

3. Hedging Arrangements

The Trust uses derivative instruments to manage its exposure to variability in cash flow from changes in commodity prices.

On November 16, 2011, Chesapeake novated the derivative contracts described in the table below to the Trust pursuant to which the Trust became party to hedging arrangements covering a portion of its oil and natural gas liquids production from October 1, 2011 through September 30, 2015. These commodity derivative contracts consist of fixed-price oil swaps, in which the Trust receives a fixed price and pays a floating market price, based on New York Mercantile Exchange (NYMEX), to the counterparty for the underlying commodity of the derivative. As a party to these contracts, the Trust will receive payments directly from its counterparty or be required to pay any amounts owed directly to its counterparty. All swaps are net settled based on the difference between the fixed-price payment and the floating-price payment. Settlements are due on a quarterly basis, including the first two months of the calendar quarter just ended and the last month of the calendar quarter prior to that one. Any payment due to or from such counterparty will be made by the 40th day following the end of the calendar quarter in which such payments become due. The first settlement date for the Trust s derivative contracts was on February 7, 2012.

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

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CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

As of March 31, 2012, the Trust had the following oil derivative instruments:

	Fixed-Price Oil Swaps		
Production Quarter	**Volume (mbbl)**	**Weighted Avg. Price (per bbl)**	**Fair Value ($ in thousands)**
Q4 2011[(1)]	55.3	$ 84.74	$ (864)
Q1 2012	163.7	84.99	(2,842)
Q2 2012	166.9	85.71	(3,091)
Q3 2012	176.6	86.40	(3,222)
Q4 2012	185.5	86.98	(3,374)
Q1 2013	182.2	87.37	(3,180)
Q2 2013	184.3	87.60	(3,006)
Q3 2013	187.9	87.79	(2,857)
Q4 2013	184.2	87.99	(2,573)
Q1 2014	179.8	88.08	(2,224)
Q2 2014	180.3	88.21	(1,949)
Q3 2014	178.8	88.34	(1,732)
Q4 2014	174.3	88.45	(1,521)
Q1 2015	171.0	88.59	(1,300)
Q2 2015	175.4	88.76	(1,099)
Q3 2015	153.6	88.90	(901)
Total	2,699.8	$ 87.56	$ (35,735)

(1) Includes December 2011 production that will be settled in May 2012. 108.2 mmbls of October and November 2011 production was settled in February 2012 at a loss of $0.8 million.

Estimated production of natural gas liquids is hedged with oil contracts using a conversion ratio of one barrel of natural gas liquids to 49.2% of a barrel of oil. Since late 2011, natural gas liquids prices have decreased relative to oil prices. To the extent oil and natural gas liquids prices are not correlated, the hedging arrangements will not effectively mitigate the price risk of the Trust s natural gas liquids production.

In accordance with accounting guidance for derivatives and hedging, and because a legal right of set-off exists, the Trust has netted the value of its hedging arrangements with the counterparty in the accompanying statement of assets, liabilities and trust corpus. Derivative liability reflected as short-term represents the estimated fair value of derivatives scheduled to settle over the next twelve months based on market prices as of March 31, 2012. The Trust does not apply hedge accounting to any of its derivative instruments, and therefore, any changes in the fair value of the derivative contracts prior to settlement will be accounted for as an adjustment to Trust corpus. Results of settled derivatives are reflected in distributable income in the period when paid. For the 2012 first quarter, the Trust settled derivative contracts for October and November 2011 production that resulted in a payment to the counterparty of $0.8 million.

4. 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. Accordingly, no provision for federal or state income tax has been made.

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CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

5. Related Party Transactions

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $175,000 to the Trustee, paid in equal quarterly installments. The administrative fee may be adjusted for inflation by no more than 3% in any calendar year beginning in 2015.

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

Pursuant to the administrative services agreement, Chesapeake provides the Trust with certain accounting, tax preparation, bookkeeping and information services related to the Royalty Interests and the registration rights agreement. In return for the services provided by Chesapeake under the administrative services agreement, the Trust pays Chesapeake, in equal quarterly installments, an annual fee of $200,000, which will remain fixed for the life of the Trust. Chesapeake is also entitled to receive reimbursement for its actual out-of-pocket fees, costs and expenses incurred in connection with the provision of any of the services under the agreement.

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

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

The Trust entered into a development agreement with Chesapeake that obligates Chesapeake to drill and complete, or cause to be drilled and completed, 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.

In drilling the Development Wells, Chesapeake is required to act diligently and as a reasonable prudent oil and gas operator would act under the same or similar circumstances as if it were acting with respect to its own properties, disregarding the existence of the Royalty Interests as burdens affecting such properties (the Reasonably Prudent Operator Standard). Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its

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CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

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

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

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

Chesapeake s drilling activity with respect to the Development Wells is consistent with its intent to meet the drilling obligation contemplated by the development agreement. As of May 10, 2012, Chesapeake had drilled and completed, or caused to be drilled or completed, a total of 24 wells in the AMI (approximately 25.9 Development Wells as calculated under the development agreement), reducing the amount that may be recovered under the Drilling Support Lien to approximately $205.1 million.

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

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 December 30, 2011, a $0.2 million non-interest bearing loan was outstanding with Chesapeake, and the loan was repaid in February 2012.

6. Fair Value Measurement

Certain financial instruments are reported at fair value on the statement of assets, liabilities and trust corpus. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair

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CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. The Trust uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities, which may or may not be observable in the market.

Cash Equivalents. The fair value of cash equivalents is based on quoted market prices.

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

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

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
		($ in thousands)		
Financial Assets (Liabilities):				
Cash equivalents	$ 1,130	$	$	$ 1,130
Derivative liabilities		(35,735)		(35,735)
Total	$ 1,130	$ (35,735)	$	$ (34,605)

7. Distributions to Unitholders

The Trust makes quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust s expenses, approximately 60 days following the completion of each quarter through (and including) the quarter ending June 30, 2031. On February 8, 2012, the Trust declared a cash distribution of $0.7277 per unit, consisting of proceeds attributable to production from September 1, 2011 through November 30, 2011, to record unitholders as of February 20, 2012. The distribution was paid on March 1, 2012.

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CHESAPEAKE GRANITE WASH TRUST

NOTES TO FINANCIAL STATEMENTS (Continued)

(Unaudited)

8. Subsequent Events

On May 10, 2012, the Trust declared a cash distribution of $0.6588 per unit, consisting of proceeds attributable to production from December 1, 2011 to February 29, 2012, to record unitholders as of May 21, 2012. The distribution will be paid on or about May 31, 2012. Distributable income attributable to production from December 1, 2011 to February 29, 2012 was calculated as follows (in thousands except for unit and per unit amounts):

Revenues:	
Royalty income[1]	$ 34,555
Total Revenues	$ 34,555
Expenses:	
Production taxes	798
Trust administrative expenses	389
Derivative settlement loss	2,567
Total Expenses	3,754
Distributable income available to unitholders	$ 30,801
Distributable income per unit (46,750,000 units issued and outstanding)	$ 0.6588

(1) Net of certain post-production expenses.

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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 unaudited interim financial statements and the accompanying notes relating to the Trust and the Underlying Properties included in Item 1 of Part I of this Quarterly Report as well as the Trust s Annual Report on Form 10-K for the year ended December 31, 2011 (the 2011 Form 10-K). Capitalized items in this Item 2 have the same meanings ascribed to them in Note 1 to the Trust s financial statements included in Item 1 of Part I of 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 3 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 of the Royalty Interests to the Trust.

Concurrent with the initial public offering, Chesapeake conveyed the Royalty Interests to the Trust effective July 1, 2011, which included interests in (a) 69 Producing Wells in the Colony Granite Wash play and (b) 118 Development Wells that have been or that are to be drilled in the Colony Granite Wash play on properties within the AMI. Chesapeake intends to drill and complete, or cause to be drilled and completed, the Development Wells from drill sites in the AMI by June 30, 2015 and is obligated to complete such drilling by June 30, 2016. As of March 31, 2012, Chesapeake had drilled and completed 21 wells within the AMI (approximately 22.7 Development Wells as calculated under the development agreement). As of May 10, 2012, Chesapeake had drilled and completed a total of 24 wells in the AMI (approximately 25.9 Development Wells as calculated under the development agreement) and had drilled, or caused to be drilled, four additional wells in the AMI that were awaiting completion.

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 may not drill and complete any well in the Colony Granite Wash formation on acreage included within the AMI for its own account until it has satisfied its drilling obligation to the Trust.

The Royalty Interests entitle the Trust to receive 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sales of production of oil, 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 sales of oil, natural gas liquids and natural gas production attributable to Chesapeake s net revenue interest in the Development Wells. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, 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 derivative contracts as of March 31, 2012 was a liability of $35.7 million.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust s administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. The first quarter 2012 distribution, consisting of proceeds attributable to production from September 1, 2011 through November 30, 2011, was made on March 1, 2012 to record unitholders as of February 20, 2012.

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

- timing of initial sales 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;
- certain 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.

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The following table sets forth the subordination threshold and the incentive threshold for each calendar quarter through the second quarter of 2017:

Period	Subordination Threshold	Incentive Threshold
	($ per unit)	
2012:		
First Quarter [(1)]	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) A distribution of $0.6588 per unit was declared on May 10, 2012 to unitholders of record as of May 21, 2012.

Results of Trust Operations

The quarterly payments to the Trust with respect to the Royalty Interests are based on the amount of proceeds actually received by Chesapeake during the preceding calendar quarter. Proceeds from production are typically received by Chesapeake one month after production. Due to the timing of the payment of production proceeds, quarterly distributions made by Chesapeake to the Trust will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, comprised of the first two months of the quarter just ended and the last month of the quarter prior to that one. Chesapeake is required to make the Royalty Interest payments to the Trust within 35 days of the end of each calendar quarter. As a result, in February 2012, the Trust received a payment on the Royalty Interests representing royalties attributable to proceeds from sales of oil, natural gas liquids and natural gas for September 1, 2011 through November 30, 2011.

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Trust Operations for the Three Months Ended March 31, 2012

On February 8, 2012, the Trust declared a cash distribution of $0.7277 per unit covering production for the period from September 1, 2011 to November 30, 2011 to record unitholders as of February 20, 2012. The distribution was paid on March 1, 2012 and is reported as distributable income for the quarter ended March 31, 2012 due to the modified cash accounting method adopted by the Trust. Distributable income attributable to production from September 1, 2011 to November 30, 2011 was calculated as follows (in thousands except for unit and per unit amounts):

Revenues:	
Royalty income[(1)]	$ 36,070
Interest income	1
Total Revenues	$ 36,071
Expenses:	
Production taxes	752
Trust administrative expenses	362
Derivative settlement loss	824
Cash reserve withheld	114
Total Expenses	2,052
Distributable income available to unitholders	$ 34,019
Distributable income per unit (46,750,000 units issued and outstanding)	$ 0.7277

(1) Net of certain post-production expenses.

Royalty Income. Royalty income to the Trust for the three-month period ended March 31, 2012 and attributable to production from September 1, 2011 to November 30, 2011 totaled $36.1 million based upon sales of production attributable to the Royalty Interests of 177 thousand barrels (mbbls) of oil, 303 mbbls of natural gas liquids and 2,910 million cubic feet (mmcf) of natural gas. Total production for the three-month period was 965 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 three-month period ended March 31, 2012 were $86.27 per barrel (bbl), $43.06 per bbl and $2.66 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 three-month period ended March 31, 2012 totaled $0.8 million, or $0.78 per barrel of oil equivalent (boe), and were approximately 2% of royalty income.

Derivative Settlement Loss. 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. Swaps covering October and November production were settled, during the three-month period ended March 31, 2012, with proceeds from royalty income for the same period. Total losses during the period were $0.8 million, or $0.02 per unit.

Distributable Income. Distributable income paid to the Trust unitholders during the three-month period ended March 31, 2012 and attributable to production from September 1, 2011 to November 30, 2011 was $34.0 million, or $0.7277 per unit, which included a $0.5 million reduction for Trust administrative expenses and a cash reserve for the payment of future Trust administrative expenses. Distributable income was higher than the target distribution of $0.68 per unit stated in the prospectus dated November 10, 2011 relating to the initial public offering of the Trust s units (the Prospectus) primarily as a result of higher than anticipated prices for all three commodities, including the impact of certain post-production expenses. The average price received for oil sales of $86.27 per bbl for

September 1, 2011 to November 30, 2011 production exceeded the price of $81.85 per bbl assumed in preparing the target distribution level for the same period. The average price received for natural gas liquids sales of $43.06 per bbl exceeded the price of $39.73 per bbl assumed in preparing the target distribution level for the same period. The average price received for natural gas sales of $2.66 per mcf for September 1, 2011 to November 30, 2011 production exceeded the price of $2.42 per mcf assumed in preparing the target distribution level for the same period.

Development Wells. As of March 31, 2012, all of the Producing Wells were completed, 69 Producing Wells were producing and approximately 22.7 Development Wells (as calculated under the development agreement) were completed and producing. Three additional wells had been drilled in the AMI and were subsequently completed in April. The amount that could be recovered under the Drilling Support Lien as of March 31, 2012 was approximately $212 million.

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 as described below. The Trust s primary uses of cash are distributions to Trust unitholders, including, if applicable, incentive distributions to Chesapeake, payments of production taxes, payments of Trust administrative expenses, including any reserves established by the Trustee for future liabilities and repayment of loans, payments for derivative contract settlements and payments of expense reimbursements to Chesapeake for out-of-pocket expenses it incurs on behalf of the Trust. Administrative expenses include payments to the Trustee and the Delaware Trustee as well as a quarterly fee of $50,000 to Chesapeake pursuant to an administrative services agreement. Each quarter, the Trustee determines the amount of funds available for distribution. Available funds are the excess cash, if any, received by the Trust from the sales of oil, 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 previously.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust s administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. The first calendar quarter 2012 distribution of $0.7277 per unit, consisting of proceeds attributable to production from September 1, 2011 through November 30, 2011, was made on March 1, 2012 to record unitholders as of February 20, 2012.

On May 10, 2012, the Trust declared a cash distribution of $0.6588 per unit, consisting of proceeds attributable to production from December 1, 2011 to February 29, 2012, to record unitholders as of May 21, 2012. The distribution will be paid on or about May 31, 2012. Distributable income for production from December 1, 2011 to February 29, 2012 was calculated as follows (in thousands except for unit and per unit amounts):

Revenues:	
Royalty income[(1)]	$ 34,555
Total Revenues	$ 34,555
Expenses:	
Production taxes	798
Trust administrative expenses	389
Derivative settlement loss	2,567
Total Expenses	3,754
Distributable income available to unitholders	$ 30,801
Distributable income per unit (46,750,000 units issued and outstanding)	$ 0.6588

(1) Net of certain post-production expenses.

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

Pursuant to the Trust Agreement, if at any time the Trust s cash on hand (including cash reserves) is not sufficient to pay the Trust s ordinary course expenses as they become due, Chesapeake will loan funds to the Trust necessary to pay such expenses. Any funds loaned by Chesapeake pursuant to this commitment will be limited to the payment of current accounts payable or other obligations to trade creditors in connection with obtaining goods or services or the payment of other current liabilities arising in the ordinary course of the Trust s business, and may not be used to satisfy Trust indebtedness for borrowed money of the Trust. If Chesapeake loans funds pursuant to this commitment, unless Chesapeake agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid.

The Trust is not responsible for any costs related to the drilling of the Development Wells and Chesapeake granted to the Trust a lien on its interest in the AMI (except the Producing Wells and any other wells that were already producing as of July 1, 2011 and are not subject to the Royalty Interests) in order to secure the estimated amount of the drilling costs for the Trust s interests in the Development Wells. As Chesapeake fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned are released from the Drilling Support Lien and the total dollar amount that may be recovered by the Trust for Chesapeake s failure to fulfill its drilling obligation is proportionately reduced.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements. The Trust has not guaranteed the debt of any other party, nor does the Trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations other than the commodity derivative contracts disclosed in the section Hedging Arrangements in Note 3 in Part I, Item I of this Quarterly Report.

Critical Accounting Policies and Estimates

Refer to Note 2 of Part I, Item 1 for discussion of significant accounting policies and estimates. Critical accounting policies and estimates relating to the Trust are contained in Item 7 of the 2011 Form 10-K.

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 attributable to the Royalty Interests from the Producing Wells and the Development Wells through September 30, 2015. The commodity derivative contracts are settled in cash and do not require the actual delivery of a commodity at settlement. The contracts are settled based upon NYMEX prices. Under the hedging arrangements, the Trust receives payments directly from its counterparty and is required to pay any amounts owed to its counterparty. The Trust does not have the ability to enter into any additional commodity derivative contracts, except in limited circumstances involving the restructuring of the existing commodity derivatives contracts.

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The following table illustrates the application of oil swaps between oil and natural gas liquids production, notional amount and weighted average fixed prices for the hedging arrangements:

	Oil		Natural Gas Liquids	
Production Quarter	**Volume (mbbl)**	**Weighted Avg. Price (per bbl)**	**Volume (mbbl)**	**Weighted Avg. Price (per bbl)**
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	1,351.6	$ 87.78	2,295.7	$ 43.19

The obligations to the counterparty under the hedging arrangements are secured by the Royalty Interests. The value of the derivative contracts as of March 31, 2012 was a liability of $35.7 million.

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. The use of crude oil derivatives to partially mitigate the price risk of natural gas liquids production is subject to basis risk to the extent oil and natural gas liquids prices are not highly correlated.

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

Credit Risk Associated With Chesapeake. Chesapeake s ability to perform its obligations to the Trust will depend on its future financial condition 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 was limited to approximately $212 million as of March 31, 2012 and will decease as the remaining Development Wells are drilled and completed.

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

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In the event of a bankruptcy of Chesapeake or the wholly owned subsidiaries of Chesapeake that conveyed the Royalty Interests to the Trust, the Trust could lose the value of all of the Royalty Interests if a bankruptcy court were to hold that the Royalty Interests constitute an asset of the bankruptcy estate. Chesapeake could also be unable to provide support to the Trust through loans and performance of its management duties.

ITEM 4. Controls and Procedures

Evaluation of Disclosure Controls and Procedures. The Trustee maintains disclosure controls and procedures as defined in Rule 13a-15(e) and 15d-15(e) under the Securities Exchange Act of 1934, as amended (the Exchange Act), designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported within the time periods specified in the SEC s rules and forms. Disclosure controls and procedures include controls and procedures designed to ensure that information required to be disclosed by the Trust is accumulated and communicated by Chesapeake to The Bank of New York Mellon Trust Company, N.A., as Trustee of the Trust, and its employees who participate in the preparation of the Trust s periodic reports as appropriate to allow timely decisions regarding required disclosures. As of the end of the period covered by this 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.

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

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PART II. OTHER INFORMATION

ITEM 1A. Risk Factors

Risk factors relating to the Trust are contained in Item 1A of the 2011 Form 10-K. There have not been any material changes from the risk factors previously disclosed in the 2011 Form 10-K.

ITEM 6. ***Exhibits***

The following exhibits are filed or furnished 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		

Exhibit Number	Exhibit Description	Incorporated by Reference Form	SEC File Number	Exhibit	Filing Date	Filed Herewith	Furnished Herewith
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		
10.7	Development Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.7	11/21/2011		
10.8	Drilling Support Mortgage, dated as of November 16, 2011, by and between Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.8	11/21/2011		
10.9	Registration Rights Agreement, dated as of November 16, 2011, by and among Chesapeake Energy Corporation, Chesapeake Exploration, L.L.C. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.9	11/21/2011		
10.10	Derivative Contract, dated as of November 16, 2011, by and between Morgan Stanley Capital Group Inc. and Chesapeake Granite Wash Trust.	8-K	001-35343	10.10	11/21/2011		
31.1	Certification pursuant to Section 302 of the Sarbanes-Oxley Act of 2002 Trustee s Vice President.					X	
32.1	Certification pursuant to Section 906 of the Sarbanes-Oxley Act of 2002 Trustee s Vice President						X

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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: May 15, 2012

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.

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EXHIBIT INDEX

Exhibit Number	Exhibit Description	Incorporated by Reference 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		

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