CHESAPEAKE GRANITE WASH TRUST
Form 10-Q
May 06, 2016

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, 2016
[ ] Transition Report pursuant to Section 13 or 15(d) of the Securities Exchange Act of 1934
For the transition period from to .

Commission File No. 001-35343
Chesapeake Granite Wash Trust
(Exact name of registrant as specified in its charter)

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

(512) 236-6555
(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 [X]	Non-accelerated filer [ ] (Do not check if a smaller reporting company)	Smaller reporting company [ ]

Indicate by check mark whether the registrant is a shell company (as defined in Rule 12b-2 of the Exchange Act). Yes [ ] No [X]
As of May 5, 2016, 35,062,500 Common Units and 11,687,500 Subordinated Units representing beneficial interests in Chesapeake Granite Wash Trust were outstanding.

CHESAPEAKE GRANITE WASH TRUST
INDEX TO FORM 10-Q FOR THE QUARTER ENDED MARCH 31, 2016

PART I. FINANCIAL INFORMATION

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

DISCLOSURES REGARDING FORWARD-LOOKING STATEMENTS

This 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 "Trustee's Discussion and Analysis of Financial Condition and Results of Operations" in Item 2 of Part I and elsewhere herein regarding the proved oil, natural gas and NGL reserves associated with the properties underlying the Royalty Interests, the Trust's or Chesapeake's future financial position, business strategy, budgets, projected costs and plans and objectives for future operations, information regarding target distributions, statements pertaining to future development activities and costs, statements regarding the number of development wells to be completed in future periods and information regarding production and reserve growth, are forward-looking statements. Actual outcomes and results may differ materially from those projected. 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 v the uncertainty of future events or outcomes. These statements are based on certain assumptions made by the Trust, and by Chesapeake in light of its experience and perception of historical trends, current conditions and expected future developments, as well as other factors we believe are appropriate under the circumstances. However, whether actual results and developments will conform with such expectations and predictions is subject to a number of risks and uncertainties, including the risk factors discussed in Item 1A of Part I of the Trust's Annual Report on Form 10-K for the year ended December 31, 2015, and those set forth 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, except as required by applicable law.

PART I. FINANCIAL INFORMATION

ITEM 1. Financial Statements

CHESAPEAKE GRANITE WASH TRUST

STATEMENTS OF ASSETS, LIABILITIES AND TRUST CORPUS

(Unaudited)

	March 31, 2016	December 31, 2015
	($ in thousands)	
ASSETS:		
Cash and cash equivalents	$1,012	$1,149
Short-term derivative asset	—	2,109
Investment in royalty interests	487,793	487,793
Less: accumulated amortization and impairment	(444,747)	(427,660)
Net investment in royalty interests	43,046	60,133
Total assets	$44,058	$63,391
LIABILITIES AND TRUST CORPUS:		
Loan from Chesapeake	$—	$175
Total liabilities	—	175
Trust Corpus; 35,062,500 common units and 11,687,500 subordinated units authorized and outstanding	44,058	63,216
Total liabilities and Trust corpus	$44,058	$63,391

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

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CHESAPEAKE GRANITE WASH TRUST
STATEMENTS OF DISTRIBUTABLE INCOME
(Unaudited)

	Three Months Ended March 31, 2016	2015
	($ in thousands, except per unit data)	
REVENUES:		
Royalty income	$4,079	$15,828
INCOME (EXPENSES):		
Production taxes	(120)	(335)
Trust administrative expenses	(575)	(379)
Derivative settlement gain	2,109	649
Total income (expenses)	1,414	(65)
Distributable income available to unitholders	$5,493	$15,763
Distributable income per common unit (35,062,500 units)	$0.1567	$0.4496
Distributable income per subordinated unit (11,687,500 units)	$—	$—

CHESAPEAKE GRANITE WASH TRUST
STATEMENTS OF CHANGES IN TRUST CORPUS
(Unaudited)

	Three Months Ended March 31, 2016	2015
TRUST CORPUS: Beginning of period	$63,216	$256,604
Cash reserve surplus	38	102
Amortization of investment in royalty interests	(2,339)	(8,652)
Impairment of investment in royalty interests	(14,748)	(58,325)
Change in derivative asset and liability	(2,109)	2,284
Distributable income	5,493	15,763
Distributions paid to unitholders	(5,493)	(15,763)
TRUST CORPUS: End of period	$44,058	$192,013

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

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 in June 2011 under the Delaware Statutory Trust Act pursuant to an initial trust agreement by and among Chesapeake Energy Corporation ("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 within an area of mutual interest (the "AMI") in the Colony Granite Wash play in Washita County in the Anadarko Basin of western Oklahoma (the “Underlying Properties”). Chesapeake conveyed the Royalty Interests to the Trust from (a) Chesapeake’s interests in 69 existing horizontal wells (the “Producing Wells”), and (b) Chesapeake’s interests in 118 horizontal development wells (the “Development Wells”) that have since been, or that are to be, drilled on properties held by Chesapeake within the AMI. Pursuant to a development agreement with the Trust, Chesapeake is obligated to drill, cause to be drilled or participate as a non-operator in the drilling of the 118 Development Wells by June 30, 2016. Additionally, based on Chesapeake’s assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. Chesapeake has retained an interest in each of the Producing Wells and Development Wells and currently operates 96% of the Producing Wells and the completed Development Wells and expects to operate all of the remaining Development Wells. As of March 31, 2016, Chesapeake had drilled and completed 98 wells within the AMI (approximately 106 of the 118 Development Wells as calculated under the development agreement). As of May 2, 2016, Chesapeake had drilled and completed 105 wells within the AMI (approximately 115 of the 118 Development Wells as calculated under the development agreement) and had drilled three additional wells within the AMI that were awaiting completion. Chesapeake anticipates that it will fulfill the drilling obligation on or before June 30, 2016.

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. The royalty interests in the Producing Wells entitle the Trust to receive 90% of the proceeds (exclusive of any production or development costs but after deducting certain post-production expenses and any applicable taxes) from the sales of oil, natural gas and natural gas liquids (NGL) production attributable to Chesapeake’s net revenue interest in the Producing Wells. The royalty interests in the Development Wells entitle the Trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting certain post-production expenses and any applicable taxes) from the sales of oil, natural gas and NGL production attributable to Chesapeake’s net revenue interest in the Development Wells.

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

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

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter (the “incentive threshold”). The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. At the end of the fourth full calendar quarter following Chesapeake’s satisfaction of its drilling obligation with respect to the Development Wells, the subordinated units will automatically convert into common units on a one-for-one basis and Chesapeake’s right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share on a pro rata basis in the Trust’s distributions.

The Trust's quarterly calculated income available for distribution for the three months ended March 31, 2016, consisting of proceeds attributable to production from September 1, 2015 to November 30, 2015, was $0.1567 per common unit. A distribution of $0.2195 per common unit was paid on March 1, 2016 to common unitholders of record, other than Chesapeake. Chesapeake received $0.0369 per common unit and waived its right to receive the higher distribution on its units with respect to the 2016 first quarter distribution. As the Trust's quarterly calculated income available for distribution was below the subordination threshold, no distribution was paid for the subordinated units. All of the subordinated units are held by Chesapeake. See Note 6 for additional information related to the quarterly cash distributions and Risks and Uncertainties in Note 2 below.

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

2. Basis of Presentation and Significant Accounting Policies

Basis of Accounting. The accompanying Statement of Assets, Liabilities and Trust Corpus as of December 31, 2015 and the unaudited interim financial statements of the Trust as of and for the three months ended March 31, 2016 and 2015, 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 to fairly state the Trust's financial position and results of operations for the periods presented. The accompanying unaudited interim financial statements should be read in conjunction with the December 31, 2015 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, 2015. These financial statements have been prepared in accordance with the instructions to Form 10-Q and, therefore, do not include all disclosures required for financial statements prepared in conformity with accounting principles generally accepted in the United States of America (GAAP).

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

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

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

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

Risks and Uncertainties. The Trust's revenue and distributions are substantially dependent upon the prevailing and future prices for oil, natural gas and NGL, 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 and NGL prices historically have been volatile, and may be subject to significant fluctuations in the future. The Trust's derivative contracts, which were only in effect through September 30, 2015, served to mitigate the effect of this price volatility on a portion of the Trust's anticipated oil and NGL production. Beginning October 1, 2015, all of the production attributable to the Trust's Royalty Interests is subject to market prices. See Note 3 for discussion of the Trust's derivative contracts.

The Trust's income available for distribution throughout 2015 and continuing into 2016 has been adversely affected by several factors. Oil and natural gas prices declined significantly throughout 2015 and remain low. The Trust's revenues and distributable income available to unitholders have been and will continue to be adversely affected if commodity prices remain at current levels or decline further. For the quarterly production period from September 1, 2015 to November 30, 2015, the Trust's calculated distribution per common unit was below the applicable subordination threshold and no subordinated distribution was paid. On May 6, 2016, the Trust declared a cash distribution of $0.0403 per common unit, consisting of proceeds attributable to production from December 1, 2015 to February 29, 2016. All of the quarterly income available for distribution will be used to make the common unit distribution and no subordinated unit distribution will be paid. The distribution will be paid on May 31, 2016 to record unitholders as of May 20, 2016. See Note 6 for information regarding prior distributions paid and Note 7 for information regarding the distribution to be paid on May 31, 2016.

During the three months ended March 31, 2016, approximately $2.1 million or 38% of the distributable income available to common unitholders was attributable to derivative settlement gains, or hedging activities. As disclosed in Note 3 below, the derivative contracts were initially novated to the Trust in November 2011 and covered a portion of the production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015, but did not cover any production subsequent to September 30, 2015. Settlement of these derivative contracts continued through February 2016.

For the three months ended March 31, 2016 and 2015, the Trust recognized approximately $14.7 million and $58.3 million, respectively, in impairments of the Royalty Interests primarily due to a decrease in commodity prices used to calculate the proved reserves attributable to the Trust's interest in the Underlying Properties. See Investment in Royalty Interests below for further discussion of the impairments.

Chesapeake's ability to perform its obligations to the Trust will depend on its future results of operations, financial condition and liquidity, which in turn will depend upon the supply and demand for oil, natural gas and NGL, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

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 monetary 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 under the Drilling Support Lien in a foreclosure or other action was limited to approximately $27 million as of March 31, 2016 and further reduced to approximately $8 million as of May 2, 2016. The maximum amount that may be recovered under the Drilling Support Lien will decrease as the remaining Development Wells are 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 could 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 would likely be insufficient to fund the drilling and completion of the number of wells needed for the Trust to realize the full value of the Royalty Interests in the

Development Wells.

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

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

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

On a quarterly basis, the Trust evaluates the carrying value of the Investment in Royalty Interests under the full cost accounting rules of 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. During the three months ended March 31, 2016 and 2015, the Trust recorded $14.7 million and $58.3 million, respectively, in impairments to the carrying value of the Investment in Royalty Interests. The impairments were primarily due to a decrease in commodity prices. The impairments resulted in non-cash charges to Trust corpus and did not affect the Trust's distributable income. Based on first-day-of-the-month index prices over the 11 months ended May 1, 2016, as well as the current strip price for June 2016, the Trust expects to record another write-down in the carrying value of the Investment in Royalty Interests in the second quarter of 2016. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters. See Risks and Uncertainties above for further discussion.

Derivatives. To mitigate a portion of the exposure to adverse market changes of oil prices, the Trust had derivative contracts covering a portion of oil production through September 30, 2015. See Note 3 for discussion of the derivative contracts.

The Trust recorded gains or losses from the derivative contracts when proceeds were received or payments were made, respectively. Additionally, changes in the fair value of the derivative contracts were accounted for as an adjustment to Trust corpus and the fair value carried on the Statements of Assets, Liabilities and Trust Corpus. Cash distributions to unitholders were increased or decreased by settlements of the Trust's derivative contracts. The Trust continued to settle the derivative contracts through February 2016.

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 Statements of Assets, Liabilities and Trust Corpus until repaid. A loan neither increases nor decreases distributions to unitholders; however, unless Chesapeake agrees otherwise, no further distributions will be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until the loan is repaid. There were no loans outstanding as of March 31, 2016. As of December 31, 2015, a $175,000 loan was outstanding with Chesapeake and the loan was repaid in March 2016. Chesapeake agreed to permit the Trust to continue making distributions while the loan was outstanding.

Revenues and Expenses. 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 revenues with respect to the Royalty Interests in the Underlying Properties are net of existing royalties and overriding royalties associated with Chesapeake's interests and are determined after deducting certain post-production expenses and any applicable taxes associated with the Royalty Interests. Post-production expenses generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas and NGL produced. However, the Trust is not responsible for costs of marketing services provided by affiliates of Chesapeake. Cash distributions to unitholders are reduced by the Trust's general and administrative expenses and cash settlements on derivatives.

3. Derivative Contracts

The Trust did not have derivatives on the balance sheet as of March 31, 2016 and will not have derivatives in future periods. All of the Trust's derivative contracts expired on September 30, 2015. The Trust's derivative contracts

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

were intended to manage its exposure to adverse changes in oil prices. On November 16, 2011, Chesapeake novated the derivative contracts described in the table below to the Trust pursuant to which the Trust became party to derivative contracts covering a portion of its expected production from October 1, 2011 through September 30, 2015. These derivative contracts consisted of fixed-price oil swaps in which the Trust received a fixed price and paid a floating market price based on New York Mercantile Exchange (NYMEX) settlement prices to the counterparty for the underlying commodity of the derivative. 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 is required to be made by the 40th day following the end of the calendar quarter in which such payment became due. The Trust continued to settle the derivative contracts through February 2016 for production through September 30, 2015. As a party to these contracts, the Trust received payments directly from its counterparty or was required to pay any amounts owed directly to the counterparty.

Additional Disclosures Regarding Derivative Contracts

In accordance with accounting guidance for derivatives and hedging, and because a legal right of set-off existed, the Trust has netted the value of its derivative contracts with the counterparty in the accompanying Statements of Assets, Liabilities and Trust Corpus as of December 31, 2015. The Trust did not apply hedge accounting to any of its derivative contracts, and therefore, any changes in the fair value of the derivative contracts prior to settlement were accounted for as an adjustment to Trust corpus. Results of settled derivative contracts were reflected in distributable income in the period when paid. For the three months ended March 31, 2016 and 2015, the Trust settled derivative contracts that resulted in receipts from the counterparty of $2.1 million and $0.6 million, respectively.

The following table presents the fair value and location of each derivative contract classification disclosed in the Statements of Assets, Liabilities and Trust Corpus as of December 31, 2015 on a gross basis without regard to same-counterparty netting:

	Statements of Assets, Liabilities and Trust Corpus Location	December 31, 2015
Asset Derivatives:		
Not designated as hedging instrument		
Commodity contracts	Short-term derivative asset	$ 2,109
Total derivative instruments		$ 2,109

All of the Trust’s derivative positions were subject to netting arrangements which provide for offsetting of asset and liability positions, as well as related cash collateral if applicable. Such netting arrangements generally did not have restrictions. Under such netting arrangements, the Trust offset the fair value of derivative instruments with cash collateral received or paid for those contracts executed with the same counterparty, which reduced the Trust’s total assets and Trust corpus. As of December 31, 2015, the Trust did not have any cash collateral balances for these derivatives.

Fair Value Measurement

Certain financial instruments are reported at fair value on the Statements of Assets, Liabilities and Trust Corpus. Under fair value measurement accounting guidance, fair value is defined as the amount that would be received from the sale of an asset or paid for the transfer of a liability in an orderly transaction between market participants, i.e., an exit price. To estimate an exit price, a three-level hierarchy is used. The fair value hierarchy prioritizes the inputs, which refer broadly to assumptions market participants would use in pricing an asset or a liability, into three levels. Level 1 inputs are unadjusted quoted prices in active markets for identical assets and liabilities and have the highest priority. Level 2 inputs are inputs other than quoted prices within Level 1 that are observable for the asset or liability, either directly or indirectly. Level 3 inputs are unobservable inputs for the financial asset or liability and have the lowest priority. The Trust uses a market valuation approach based on available inputs and the following methods and assumptions to measure the fair values of its assets and liabilities.

Fair Value of Derivatives. The fair value of the Trust's derivatives was based on the NYMEX settlement price. These values were compared to the values given by the Trust's counterparty for reasonableness. Since commodity swaps do not include optionality and therefore generally have no unobservable inputs, they were classified as Level 2.

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

The following table provides fair value measurement information for derivative assets measured at fair value on a recurring basis as of December 31, 2015:

	Quoted Prices in Active Markets (Level 1)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
	($ in thousands)			
As of December 31, 2015				
Total derivative assets	$—	$ 2,109	$ —	$ 2,109

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

4. Income Taxes

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

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

5. Related Party Transactions

Trustee Administrative Fee. Under the terms of the Trust Agreement, the Trust pays an annual administrative fee of $175,000 to the Trustee, paid in equal quarterly installments. The administrative fee may be adjusted for inflation by no more than 3% in any calendar year beginning in 2015. As of March 31, 2016, no inflation adjustment has been made.

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 services 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. The Trust has no derivative contracts as of March 31, 2016.

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 transferred by Chesapeake to a third party, 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 upon by Chesapeake and the Trustee.

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

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

In drilling the Development Wells, Chesapeake is required to act diligently and as a reasonably prudent oil and gas operator would act under the same or similar circumstances as if it were acting with respect to its own properties, disregarding the existence of the Royalty Interests as burdens affecting such properties (the "Reasonably Prudent Operator Standard"). Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the remaining 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 is credited for drilling one full Development Well if the perforated length of the well is equal to or greater than 3,500 feet and Chesapeake's net revenue interest in the well is equal to 52.0%. For wells with a perforated length that is less than 3,500 feet, and for wells in which Chesapeake has a net revenue interest greater than or less than 52.0%, Chesapeake receives proportionate credit.

A wholly owned subsidiary of Chesapeake has granted to the Trust the Drilling Support Lien covering Chesapeake's retained interest in the AMI (except its interest in the Producing Wells, Development Wells and any other wells not subject to the Royalty Interests) in order to secure the estimated amount of the drilling costs for the Trust's interests in the Development Wells. The maximum amount that could be obtained by the Trust pursuant to the Drilling Support Lien initially was $262.7 million. As Chesapeake fulfills its drilling obligation over time, the total recoverable amount is proportionately reduced and completed Development Wells are released from the lien. As of March 31, 2016, the maximum amount the Trust could recover under the Drilling Support Lien was limited to approximately $27 million. 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 2, 2016, Chesapeake had drilled and completed 105 wells within the AMI (approximately 115 of the 118 Development Wells as calculated under the development agreement), reducing the amount that may be recovered under the Drilling Support Lien to approximately $8 million, and had drilled three additional wells within the AMI that were awaiting completion.

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. There were no loans outstanding as of March 31, 2016. As of December 31, 2015, a $175,000 loan was outstanding with Chesapeake and the loan was repaid in March 2016. Chesapeake agreed to permit the Trust to continue making distributions while the loan was outstanding.

6. 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.

For the three months ended March 31, 2016 and 2015, the Trust declared and paid the following cash distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit [(a)] Public unitholders other than Chesapeake	Cash Distribution per Common Unit [(a)] Chesapeake	Cash Distribution per Subordinated Unit
September 2015 - November 2015	March 1, 2016	$0.2195	$ 0.0369	$ —
September 2014 - November 2014	March 2, 2015	$0.4496	$ 0.4496	$ —

(a) In its press release dated February 4, 2016, the Trust incorrectly announced that the distributable income for the quarter ended December 31, 2015 was $0.2195 per common unit. Chesapeake advised the Trust that Chesapeake included an incorrect amount for the derivative settlement gain in the prior calculation of distributable income. Chesapeake elected to waive its right to the higher distribution on common units held by Chesapeake with respect to the 2016 first quarter distribution. As a result, Chesapeake's distribution was reduced by approximately $1.4 million to allow all other common unitholders to receive a distribution of $0.2195 per common unit as previously announced. Chesapeake received a distribution of $0.0369 per common unit.

CHESAPEAKE GRANITE WASH TRUST
NOTES TO FINANCIAL STATEMENTS - (Continued)
(Unaudited)

7. Subsequent Events

On May 6, 2016, the Trust declared a cash distribution of $0.0403 per common unit, consisting of proceeds attributable to production from December 1, 2015 to February 29, 2016. The distribution will be paid on May 31, 2016 to record unitholders as of May 20, 2016. The Trust's quarterly income available for distribution was $0.0302 per unit, which was $0.4798 below the applicable subordination threshold of $0.5100. All of the quarterly income available for distribution will be used to make the common unit distribution and no subordinated unit distribution will be paid. Distributable income attributable to production from December 1, 2015 to February 29, 2016 was calculated as follows (in thousands except for unit and per unit amounts):

REVENUES:	
Royalty income[(a)]	$2,354
EXPENSES:	
Production taxes	(118)
Trust administrative expenses[(b)]	(824)
Total expenses	(942)
Distributable income available to unitholders	$1,412
Distributable income per common unit (35,062,500 units)	$0.0403
Distributable income per subordinated unit (11,687,500 units)[(c)]	$—

(a) Net of certain post-production expenses.
(b) Includes cash reserves withheld.
(c) As the common unit distribution is below the applicable subordination threshold, no distribution was declared for the subordinated units.

In April 2016, the Trust's cash on hand (including cash reserves) was not sufficient to pay the Trust's ordinary course expenses as they became due. Chesapeake loaned $200,000 to the Trust necessary to pay such expenses and agreed to permit the Trust to continue making distributions while the loan was outstanding. The loan was repaid in May 2016.

ITEM 2. Trustee's Discussion and Analysis of Financial Condition and Results of Operations

Introduction

The following discussion and analysis is intended to help the reader understand the Trust's financial condition and results of operations. This discussion and analysis should be read in conjunction with the 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, 2015 (the "2015 Form 10-K").

Overview

The Trust is a statutory trust formed in June 2011 under the Delaware Statutory Trust Act. The business and affairs of the Trust are managed by the Trustee and, as necessary, the Delaware Trustee. The Trust does not conduct any operations or activities other than owning the Royalty Interests and activities related to such ownership. The Trust's purpose is generally to own the Royalty Interests, to distribute to the Trust unitholders cash that the Trust receives in respect of the Royalty Interests and the derivative contracts (described in Note 3 to the financial statements contained in Item 1 of Part I 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, through March 31, 2016, net gains on settlements of the derivative contracts. The Trust is treated as a partnership for federal income tax purposes.

Concurrent with the Trust's initial public offering in November 2011, 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 since been or that are to be drilled in the Colony Granite Wash play on properties within the AMI. Chesapeake is obligated to drill, cause to be drilled or participate as a non-operator in the drilling of the Development Wells from drill sites in the AMI on or prior to June 30, 2016. Additionally, based on Chesapeake's assessment of the ability of a Development Well to produce in paying quantities, Chesapeake is obligated to either complete and tie into production or plug and abandon each Development Well. As of March 31, 2016, Chesapeake had drilled and completed 98 wells within the AMI (approximately 106 of the 118 Development Wells as calculated under the development agreement). As of May 2, 2016, Chesapeake had drilled and completed 105 wells within the AMI (approximately 115 of the 118 Development Wells as calculated under the development agreement) and had drilled three additional wells within the AMI that were awaiting completion. Chesapeake anticipates that it will fulfill the drilling obligation on or before June 30, 2016.

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

The Royalty Interests entitle the Trust to receive 90% of the proceeds (after deducting certain post-production expenses and any applicable taxes) from the sales of production of oil, natural gas and NGL 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 and NGL 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 and NGL produced. However, the Trust is not responsible for costs of marketing services provided by Chesapeake or its affiliates.

On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering a portion of the production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015. The Trust's distributable income included net settlements under these derivative contracts. As of March 31, 2016, the Trust had settled all derivative contracts. As of December 31, 2015, the fair value of the derivative contracts was a net asset of $2.1 million.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. During the three months ended March 31, 2016, a distribution was

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paid on March 1, 2016. See Liquidity and Capital Resources below and Note 6 to the financial statements contained in Item 1 Part I of this Quarterly Report for more information regarding the distributions.

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

- timing and amount of initial production and sales from the Development Wells;
- oil, natural gas and NGL prices received;
- volumes of oil, natural gas and NGL produced and sold;
- certain post-production expenses and any applicable taxes;
- the Trust’s expenses; and
- through March 31, 2016, the Trust revenues and cash distributions to Trust unitholders were also affected by amounts received from, or paid under, derivative contracts.

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

Incentive Threshold. In exchange for agreeing to subordinate a portion of its Trust units, and in order to provide additional financial incentive to Chesapeake to satisfy its drilling obligation and perform operations on the Underlying Properties in an efficient and cost-effective manner, Chesapeake is entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter. The remaining 50% of cash available for distribution in excess of the applicable incentive threshold is 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. With respect to distributions for quarters following the fourth full quarter after Chesapeake's satisfaction of its Development Well drilling obligation, the common units will no longer have the protection of the subordination threshold, and all Trust unitholders will share on a pro rata basis in the Trust’s distributions. The period during which the subordinated units are outstanding is referred to as the subordination period.

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

Period	Subordination Threshold[(a)] (per unit)	Incentive Threshold[(a)]
2016:		
First Quarter [(b)]	$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

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

(b) A distribution of $0.0403 per common unit was declared on May 6, 2016 to unitholders of record as of May 20, 2016. The distribution will be paid on May 31, 2016. As the common unit distribution was below the subordination threshold, no distribution was declared for the subordinated units.

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 generally include royalties attributable to sales of oil, natural gas and NGL 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. During the three months ended March 31, 2016, the Trust received payments on the Royalty Interests representing royalties attributable to proceeds from sales of oil, natural gas and NGL for September 1, 2015 to November 30, 2015.

The Trust’s income available for distribution throughout 2015 and continuing into 2016 has been adversely affected by several factors. Oil and natural gas prices declined significantly throughout 2015 and remain low. The Trust's revenues and distributable income available to unitholders have been and will continue to be adversely affected if commodity prices remain at current levels or decline further. For the quarterly production period from September 1, 2015 to November 30, 2015, the Trust's calculated distribution per common until was below the applicable subordination threshold and no subordinated distribution was paid.

Low levels of future production and low commodity prices will continue to reduce the Trust’s revenues and distributable income available to unitholders and will likely result in continued distributions to common unitholders below the subordination threshold. When a quarterly cash distribution in respect of the common units is lower than the applicable subordination threshold, the common units are not entitled to receive any additional distributions, nor are the common units or the subordinated units entitled to arrearages in any future quarter. During the three months ended March 31, 2016, approximately $2.1 million or 38% of the distributable income available to common unitholders was attributable to derivative settlement gains, or hedging activities. As disclosed in Note 3 to the financial statements contained in Item 1 of Part I of this Quarterly Report, the derivative contracts were initially novated to the Trust in November 2011 and covered a portion of the production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015, but did not cover any production subsequent to September 30, 2015. Settlement of these derivative contracts continued through February 2016. As a result of the termination of these derivative contracts, it is

anticipated that Trust revenues and funds available for distribution will be further reduced as long as low commodity prices continue.

For the three months ended March 31, 2016 and 2015, the Trust recognized approximately $14.7 million and $58.3 million in impairments of the Royalty Interests, respectively. The impairments were primarily the result of a decrease in commodity prices. The impairments resulted in non-cash charges to Trust corpus and did not affect the Trust's distributable income. See Investment in Royalty Interests in Note 2 to the financial statements contained in Item 1 of Part I of this Quarterly Report and Trust Operations below for further discussion of the impairments.

Trust Operations for the Three Months Ended March 31, 2016 as compared to March 31, 2015.

Distributable Income. The Trust's distributable income was $5.5 million for the three months ended March 31, 2016 compared to $15.8 million for the three months ended March 31, 2015, a decrease of $10.3 million. This decrease was primarily due to a decrease in the average realized prices received from sales of oil, natural gas and NGL and a decrease in production volumes in the production period from September 1, 2015 to November 30, 2015 ("current production quarter") as compared to the production period from September 1, 2014 to November 30, 2014 ("prior production quarter"). The decrease was partially offset by derivative gains. See Royalty Income below for information regarding the change in average prices received and the change in sales volumes.

On a per unit basis, the Trust's distributable income for the three months ended March 31, 2016 and attributable to the current production quarter was $0.1567. A cash distribution of $0.2195 per common unit was paid to common unitholders of record, other than Chesapeake. Chesapeake received $0.0369 per common unit and waived its right to receive the higher distribution on its units with respect to the 2016 first quarter distribution. No subordinated distribution was paid. Cash distributions during the three months ended March 31, 2015 and attributable to the prior production quarter were $0.4496 per common unit and no subordinated distribution was paid. Distributable income for each of the three months ended March 31, 2016 and 2015, and their respective production periods described above, was calculated as follows:

	Three Months Ended March 31,	
	2016	2015
	($ in thousands, except per unit data)	
REVENUES:		
Royalty income[(a)]	$4,079	$15,828
INCOME (EXPENSES):		
Production taxes	(120)	(335)
Trust administrative expenses[(b)]	(575)	(379)
Derivative settlement gain	2,109	649
Total income (expenses)	1,414	(65)
Distributable income available to unitholders	$5,493	$15,763
Distributable income per common unit (35,062,500 units)	$0.1567	$0.4496
Distributable income per subordinated unit (11,687,500 units)[(c)]	$—	$—

(a) Net of certain post-production expenses.

(b) Includes cash reserves withheld.

(c) For the three months ended March 31, 2016 and 2015, the Trust's calculated distributable income was below the applicable subordination threshold. As a result, no distribution was paid for the subordinated units in either quarter.

Royalty Income. Royalty income to the Trust for the three months ended March 31, 2016, and attributable to the current production quarter, totaled $4.1 million based upon sales of production attributable to the Royalty Interests of 47 thousand barrels (mbbls) of oil, 1,221 million cubic feet (mmcf) of natural gas and 98 mbbls of NGL. Total production

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attributable to the Royalty Interests for the current production quarter was 349 thousand barrels of oil equivalent (mboe). Average prices received for production, including the impact of certain post-production expenses and excluding production taxes, during the current production quarter were $37.60 per barrel (bbl) of oil, $0.62 per thousand cubic feet (mcf) of natural gas and $15.87 per bbl of NGL.

Royalty income to the Trust for the three months ended March 31, 2015, and attributable to the prior production quarter, totaled $15.8 million based upon sales of production attributable to the Royalty Interests of 74 mbbls of oil, 1,821 mmcf of natural gas and 203 mbbls of NGL. Total production attributable to the Royalty Interests for the prior production quarter was 581 mboe. Average prices received for production, including the impact of certain post-production expenses and excluding production taxes, during the prior production quarter were $80.71 per bbl of oil, $2.36 per mcf of natural gas and $27.24 per bbl of NGL.

The decrease in the price received per barrel of oil equivalent (boe) in the current production quarter compared to the prior production quarter resulted in a $5.4 million decrease in royalty income, and lower sales volumes resulted in a $6.3 million decrease in royalty income, for a net decrease in royalty income of $11.7 million.

Production Taxes. Production taxes are calculated as a percentage of oil, natural gas and NGL revenues, net of any applicable tax credits. Production taxes for the three months ended March 31, 2016, and attributable to the current production quarter, were $0.1 million, or $0.34 per boe, as compared to production taxes for the three months ended March 31, 2015, and attributable to the prior production quarter, of $0.3 million, or $0.58 per boe. The decrease in production taxes is primarily due to the decline in commodity prices and lower sales volumes. Production taxes represented approximately 2.9% and 2.1% of royalty income for the three months ended March 31, 2016 and 2015, respectively.

Trust Administrative Expenses. Trust administrative expenses, including additional cash reserves, for the three months ended March 31, 2016 totaled $0.6 million as compared to $0.4 million for the three months ended March 31, 2015. Trust administrative expenses primarily consist of the administrative fees paid to the Trustees and Chesapeake and costs for accounting and legal services.

Cash Settlements on Derivatives. The Trust recorded gains or losses from the derivative contracts when proceeds were received or payments were made, respectively. Swaps covering the current production quarter were settled during the three months ended March 31, 2016, and proceeds received were included in the Trust's distributable income for the current production quarter. Total gains during the three months ended March 31, 2016 were $2.1 million. Swaps covering the prior production quarter were settled during the three months ended March 31, 2015, and proceeds received were included in the Trust's distributable income for the prior production quarter. Total gains during the three months ended March 31, 2015 were $0.6 million.

Impairments of Royalty Interests. During the three months ended March 31, 2016 and 2015, the Trust recognized approximately $14.7 million and $58.3 million in impairments of the Royalty Interests, respectively. The impairments were primarily due to a decrease in commodity prices used to calculate the proved reserves attributable to the Trust's interest in the Underlying Properties. The impairments resulted in a non-cash charge to Trust corpus and did not affect the Trust's distributable income.

As of March 31, 2016, the present value of the estimated future net revenue of the proved reserves attributable to the Trust's interest in the Underlying Properties, discounted at an annual rate of 10%, was $43.0 million. Estimated future net revenue represents the estimated future gross revenue to be generated from the production of proved reserves, net of estimated production and future development costs, using prices and costs under existing economic conditions as of that date. Based on the first-day-of-the month index prices we have received over the 11 months ended May 1, 2016, as well as the current strip price for June 2016, the Trust reasonably expects a decrease of approximately $3.40 per bbl of oil and $0.16 per mcf of natural gas in the prices we will be using to calculate the estimated future net revenue of the proved reserves attributable to the Trust's interest in the Underlying Properties as of June 30, 2016, and such decreases are expected to reduce the present value of estimated future net revenue of the proved reserves attributable to the Trust's interest in the Underlying Properties by approximately $14.0 million in the 2016 second quarter. Such decrease is likely to be a significant factor in the amount of impairment recorded in the 2016 second quarter. Further material write-downs in subsequent quarters will occur if the trailing 12-month commodity prices continue to fall as compared to the commodity prices used in prior quarters. See Risks and Uncertainties in Note 2 of

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the notes to the financial statements included in Item 1 of Part I of this Quarterly Report for further discussion of the impairments.

Liquidity and Capital Resources

The Trust's principal sources of liquidity and capital are cash flows generated from the Royalty Interests and the loan commitment as described below and, prior to the expiration of the derivative contracts on September 30, 2015, cash settlements on derivative contracts during periods in which oil prices fell below the fixed price received on derivative contracts. The Trust's primary uses of cash are distributions to Trust unitholders, including, if applicable, incentive distributions to Chesapeake, payments of production taxes, payments of Trust administrative expenses, including any reserves established by the Trustee for future liabilities and repayment of loans and payments 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 sales of oil, natural gas and NGL 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. A distribution of $0.2195 per common unit, consisting of proceeds attributable to production from September 1, 2015 to November 30, 2015, was paid on March 1, 2016 to common unitholders of record, other than Chesapeake, as of February 19, 2016. Chesapeake received $0.0369 per common unit and waived its right to receive the higher distribution on its units with respect to the 2016 first quarter distribution. The Trust's distributable income was $0.1567 per common unit. As the distributable income per common unit was below the subordination threshold, no distribution was declared for the subordinated units.

On May 6, 2016, the Trust declared a cash distribution of $0.0403 per common unit, consisting of proceeds attributable to production from December 1, 2015 to February 29, 2016. The distribution will be paid on May 31, 2016 to record unitholders as of May 20, 2016. The Trust's quarterly income available for distribution was $0.0302 per unit, which was $0.4798 below the applicable subordination threshold of $0.5100. All of the quarterly income available for distribution will be used to make the common unit distribution and no subordinated unit distribution will be paid. Distributable income attributable to production from December 1, 2015 to February 29, 2016 was calculated as follows (in thousands except for unit and per unit amounts):

REVENUES:	
Royalty income[(a)]	$2,354
EXPENSES:	
Production taxes	(118)
Trust administrative expenses[(b)]	(824)
Total expenses	(942)
Distributable income available to unitholders	$1,412
Distributable income per common unit (35,062,500 units)	$0.0403
Distributable income per subordinated unit (11,687,500 units)[(c)]	$—

(a) Net of certain post-production expenses.

(b) Includes cash reserves withheld.

(c) As the common unit distribution is below the applicable subordination threshold, no distribution was declared for the subordinated units.

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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 may be made to unitholders (except in respect of any previously determined quarterly cash distribution amount) until such loan is repaid. There were no loans outstanding as of March 31, 2016. As of December 31, 2015, a $175,000 loan was outstanding with Chesapeake and the loan was repaid in March 2016. Chesapeake agreed to permit the Trust to continue making distributions while the loan was outstanding. In April 2016, Chesapeake loaned $200,000 to the Trust and agreed to permit the Trust to continue making distributions while the loan was outstanding. The loan was repaid in May 2016.

The Trust is not responsible for any costs related to the drilling of the Development Wells, and Chesapeake granted to the Trust the Drilling Support Lien 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. As of May 2, 2016, the maximum dollar amount the Trust can recover was limited to approximately $8 million.

Off-Balance Sheet Arrangements

The Trust has no off-balance sheet arrangements. The Trust has not guaranteed the debt of any other party, nor does the Trust have any other arrangements or relationships with other entities that could potentially result in unconsolidated debt, losses or contingent obligations other than the derivative contracts disclosed in the section Derivative Contracts in Note 3 in Item 1 of Part I of this Quarterly Report.

Critical Accounting Policies and Estimates

Refer to Note 2 of the notes to the Trust's financial statements included in Item 1 of Part I of this Quarterly Report for a discussion of significant accounting policies and estimates that impact the Trust's financial statements. Critical accounting policies and estimates relating to the Trust are contained in Item 7 of the 2015 Form 10-K.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

The discussion in this section provides information about the previous derivative contracts between the Trust and the derivative counterparty effective October 1, 2011 and that expired September 30, 2015. The derivative contracts covered a portion of the expected production attributable to the Royalty Interests from the Producing Wells and the Development Wells through September 30, 2015. The Trust continued to settle the derivative contracts through February 2016. The derivative contracts were settled in cash and did not require the actual delivery of oil or NGL at settlement. The contracts were settled based upon NYMEX prices. Under the derivative contracts, the Trust received payments directly from the counterparty and paid any amounts owed to the counterparty. The Trust does not have the ability to enter into any additional oil, natural gas or NGL derivative contracts.

Oil, Natural Gas and NGL Price Risk. The Trust's primary asset and source of income is the Royalty Interests, which generally entitles the Trust to receive a portion of the net proceeds from the sales of oil, natural gas and NGL from the Underlying Properties. The Trust is significantly exposed to fluctuations in the prices received for oil, natural gas and NGL produced and sold. The derivative contracts described above were designed to mitigate a portion of the variability of the prices received for the Trust's share of oil production. The prior use of crude oil derivative contracts

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to partially mitigate the price risk of NGL production was subject to basis risk to the extent oil and NGL prices were not highly correlated. All of the Trust's derivative contracts expired on September 30, 2015.

Credit Risk. A portion of the Trust’s liquidity was concentrated in the derivative contracts described above. The use of crude oil derivative contracts exposed the Trust to credit risk from the 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 results of operations, financial condition, liquidity and ability to comply with the financial covenants contained in its debt instruments, which in turn will depend upon the supply and demand for oil, natural gas and NGL, 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 $8 million as of May 2, 2016; this obligation 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 could be insufficient to drill the number of wells needed for the Trust to realize the full value of the Royalty Interests in the Development Wells.

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

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. Sarah C. Newell, as Vice President of the Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the Trust Agreement, (ii) the administrative services agreement, (iii) the development agreement and (iv) the conveyances granting the Royalty Interests, the Trustee’s disclosure controls and procedures related to the Trust necessarily rely on (a) information provided by Chesapeake, including information relating to results of operations, the status of drilling of the Development Wells, the costs and revenues attributable to the Trust’s interests under the conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the underlying properties and the Royalty Interests, and (b) conclusions and reports regarding reserves by the Trust’s independent reserve engineers. Other than reviewing the financial and other information provided to the Trust by Chesapeake, the Trustee has not made an independent or direct verification of this financial or other information.

Changes in Internal Control over Financial Reporting. During the three months ended March 31, 2016, 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

Additional information about risk factors relating to the Trust are contained in Part I, Item 1A of the 2015 Form 10-K.

ITEM 6. Exhibits

The exhibits listed below in the Index of Exhibits (following the signature page) are filed, furnished or incorporated by reference pursuant to the requirements of Item 601 of Regulation S-K.

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 6, 2016

CHESAPEAKE GRANITE WASH TRUST

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

By: /s/ Sarah C. Newell

Sarah C. Newell

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.

INDEX OF EXHIBITS

		Incorporated by Reference				
Exhibit Number	Exhibit Description	Form	SEC File Number	Exhibit	Filing Date	Filed or Furnished Herewith
3.1	Certificate of Trust of Chesapeake Granite Wash Trust.	S-1	333-175395	3.1	7/7/2011	
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, and The Corporation Trust Company, as Delaware Trustee.	8-K	001-35343	3.1	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