

PROSPECT CAPITAL CORP

Form POS EX

March 21, 2019

As filed with the Securities and Exchange Commission on March 21, 2019

Registration No. 333-227124

U.S. SECURITIES AND EXCHANGE COMMISSION

WASHINGTON, D.C. 20549

FORM N-2

REGISTRATION STATEMENT UNDER
THE SECURITIES ACT OF 1933

PRE-EFFECTIVE AMENDMENT NO.

POST-EFFECTIVE AMENDMENT NO. 21

PROSPECT CAPITAL CORPORATION

(Exact Name of Registrant as Specified in Charter)

10 East 40th Street, 42nd Floor

New York, NY 10016

(Address of Principal Executive Offices)

Registrant's Telephone Number, including Area Code: (212) 448-0702

John F. Barry III

Kristin L. Van Dask

c/o Prospect Capital Management L.P.

10 East 40th Street, 42nd Floor

New York, NY 10016

(212) 448-0702

(Name and Address of Agent for Service)

Copies of information to:

Michael K. Hoffman

Skadden, Arps, Slate, Meagher & Flom LLP

4 Times Square

New York, NY 10036

(212) 735-3000

Approximate Date of Proposed Public Offering: From time to time after the effective date of this Registration Statement.

If any of the securities being registered on this form are offered on a delayed or continuous basis in reliance on Rule 415 under the Securities Act of 1933, other than securities offered in connection with a dividend reinvestment plan, check the following box.

EXPLANATORY NOTE

This Post-Effective Amendment No. 21 to the Registration Statement on Form N-2 (File No. 333-227124) of Prospect Capital Corporation (the "Registration Statement") is being filed pursuant to Rule 462(d) under the Securities Act of 1933, as amended (the "Securities Act"), solely for the purpose of filing exhibits to the Registration Statement. Accordingly, this Post-Effective Amendment No. 21 consists only of a facing page, this explanatory note and Part C of the Registration Statement on Form N-2 setting forth the exhibits to the Registration Statement. This Post-Effective Amendment No. 21 does not modify any other part of the Registration Statement. Pursuant to Rule 462(d) under the Securities Act, this Post-Effective Amendment No. 21 shall become effective immediately upon filing with the Securities and Exchange Commission. The contents of the Registration Statement are hereby incorporated by reference.

PART C—OTHER INFORMATION

ITEM 25. FINANCIAL STATEMENTS AND EXHIBITS

(1) Financial Statements

The following statements of Prospect Capital Corporation (the “Company” or the “Registrant”) are included in Part A of this Registration Statement:

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(2) Financial Statement Schedules

The financial statements of National Property REIT Corp. and First Tower Finance Company LLC and its consolidated subsidiaries required by Rule 3-09 of Regulation S-X can be found on pages F-112 and F-191 of this Registration Statement, respectively.

(3) Exhibits

The agreements included or incorporated by reference as exhibits to this registration statement contain representations and warranties by each of the parties to the applicable agreement. These representations and warranties were made solely for the benefit of the other parties to the applicable agreement and (i) were not intended to be treated as categorical statements of fact, but rather as a way of allocating the risk to one of the parties if those statements prove to be inaccurate; (ii) may have been qualified in such agreement by disclosures that were made to the other party in connection with the negotiation of the applicable agreement; (iii) may apply contract standards of “materiality” that are different from “materiality” under the applicable securities laws; and (iv) were made only as of the date of the applicable agreement or such other date or dates as may be specified in the agreement.

The Company acknowledges that, notwithstanding the inclusion of the foregoing cautionary statements, it is responsible for considering whether additional specific disclosures of material information regarding material contractual provisions are required to make the statements in this registration statement not misleading.

Exhibit No.	Description
(a)(1)	Articles of Amendment and Restatement(1)
(b)(1)	Amended and Restated Bylaws(3)
(c)	Not Applicable
(d)(1)	Form of Share Certificate(2)
(d)(2)	Form of Indenture(9)

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(d)(3) Indenture dated as of December 21, 2010 relating to the 6.25% Senior Convertible Notes, by and between the Registrant and American Stock Transfer & Trust Company, LLC, as Trustee and Form of 6.25% Senior Convertible Note due 2015(7)

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Exhibit No.	Description
(d)(4)	Indenture dated as of February 18, 2011 relating to the 5.50% Senior Convertible Notes, by and between the Registrant and American Stock Transfer & Trust Company, LLC, as Trustee(8)
(d)(5)	Form of 5.50% Senior Convertible Note due 2016(6)
(d)(6)	Statement of Eligibility of U.S. Bank National Association on Form T-1(318)
(d)(7)	Indenture dated as of February 16, 2012, by and between the Registrant and American Stock Transfer & Trust Company, LLC, as Trustee(10)
(d)(8)	First Supplemental Indenture dated as of March 1, 2012, to the Indenture dated as of February 16, 2012, by and between the Registrant and American Stock Transfer & Trust Company, LLC, as Trustee and Form of 7.00% Prospect Capital InterNote® due 2022(10)
(d)(9)	Second Supplemental Indenture dated as of March 8, 2012, to the Indenture dated as of February 16, 2012, by and between the Registrant and American Stock Transfer & Trust Company, LLC, as Trustee(11)
(d)(10)	Joinder Supplemental Indenture dated as of March 8, 2012, to the Indenture dated as of February 16, 2012, by and among the Registrant, American Stock Transfer & Trust Company, LLC, as Original Trustee, and U.S. Bank National Association, as Series Trustee and Form of 6.900% Prospect Capital InterNote® due 2022(11)
(d)(11)	Agreement of Resignation, Appointment and Acceptance dated as of March 12, 2012, by and among the Registrant, American Stock Transfer & Trust Company, LLC, as Retiring Trustee, and U.S. Bank National Association, as Successor Trustee (12)
(d)(12)	Third Supplemental Indenture dated as of April 5, 2012, to the Indenture dated as of February 16, 2012, by and between the Registrant and U.S. Bank National Association, as Successor Trustee pursuant to the Agreement of Resignation, Appointment and Acceptance dated as of March 12, 2012, by and among the Registrant, American Stock Transfer & Trust Company, LLC, as Retiring Trustee, and U.S. Bank National Association, as Successor Trustee (the “U.S. Bank Indenture”) and Form of 6.850% Prospect Capital InterNote® due 2022(14)
(d)(13)	Fourth Supplemental Indenture dated as of April 12, 2012, to the U.S. Bank Indenture and Form of 6.700% Prospect Capital InterNote® due 2022(15)
(d)(14)	Indenture dated as of April 16, 2012 relating to the 5.375% Senior Convertible Notes, by and between the Registrant and American Stock Transfer & Trust Company, as Trustee(16)
(d)(15)	Form of 5.375% Senior Convertible Note due 2017(17)
(d)(16)	Fifth Supplemental Indenture dated as of April 26, 2012, to the U.S. Bank Indenture and Form of 6.500% Prospect Capital InterNote® due 2022(18)
(d)(17)	Indenture dated as of August 14, 2012 relating to the 5.75% Senior Convertible Notes, by and between the Registrant and American Stock Transfer & Trust Company, as Trustee(19)
(d)(18)	Form of 5.75% Senior Convertible Note due 2018(20)
(d)(19)	Nineteenth Supplemental Indenture dated as of September 27, 2012, to the U.S. Bank Indenture and Form of 5.850% Prospect Capital InterNote® due 2019(21)
(d)(20)	Twentieth Supplemental Indenture dated as of October 4, 2012, to the U.S. Bank Indenture and Form of 5.700% Prospect Capital InterNote® due 2019(22)
(d)(21)	Twenty-First Supplemental Indenture dated as of November 23, 2012, to the U.S. Bank Indenture and Form of 5.125% Prospect Capital InterNote® due 2019(23)
(d)(22)	Twenty-Second Supplemental Indenture dated as of November 23, 2012, to the U.S. Bank Indenture and Form of 6.625% Prospect Capital InterNote® due 2042(23)
(d)(23)	Twenty-Third Supplemental Indenture dated as of November 29, 2012, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2019(24)
(d)(24)	Twenty-Fourth Supplemental Indenture dated as of November 29, 2012, to the U.S. Bank Indenture and Form of 5.750% Prospect Capital InterNote® due 2032(24)
(d)(25)	

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- Twenty-Fifth Supplemental Indenture dated as of November 29, 2012, to the U.S. Bank Indenture and Form of 6.500% Prospect Capital InterNote® due 2042(24)
- (d)(26) Twenty-Sixth Supplemental Indenture dated as of December 6, 2012, to the U.S. Bank Indenture and Form of 4.875% Prospect Capital InterNote® due 2019(25)
- (d)(27) Twenty-Eighth Supplemental Indenture dated as of December 6, 2012, to the U.S. Bank Indenture and Form of 6.375% Prospect Capital InterNote® due 2042(25)
- (d)(28) Twenty-Ninth Supplemental Indenture dated as of December 13, 2012, to the U.S. Bank Indenture and Form of 4.750% Prospect Capital InterNote® due 2019(26)
- (d)(29) Thirty-First Supplemental Indenture dated as of December 13, 2012, to the U.S. Bank Indenture and Form of 6.250% Prospect Capital InterNote® due 2042(26)

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Exhibit No.	Description
(d)(30)	Thirty-Second Supplemental Indenture dated as of December 20, 2012, to the U.S. Bank Indenture and Form of 4.625% Prospect Capital InterNote® due 2019(27)
(d)(31)	Thirty-Fourth Supplemental Indenture dated as of December 20, 2012, to the U.S. Bank Indenture and Form of 6.125% Prospect Capital InterNote® due 2042(27)
(d)(32)	Indenture dated as of December 21, 2012, by and between the Registrant and American Stock Transfer & Trust Company, as Trustee and Form of Global Note 5.875% Convertible Senior Note Due 2019(28)
(d)(33)	Thirty-Fifth Supplemental Indenture dated as of December 28, 2012, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2019(29)
(d)(34)	Thirty-Sixth Supplemental Indenture dated as of December 28, 2012, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2030(29)
(d)(35)	Thirty-Seventh Supplemental Indenture dated as of December 28, 2012, to the U.S. Bank Indenture and Form of 6.000% Prospect Capital InterNote® due 2042(29)
(d)(36)	Thirty-Eighth Supplemental Indenture dated as of January 4, 2013, to the U.S. Bank Indenture and Form of 4.375% Prospect Capital InterNote® due 2020(30)
(d)(37)	Thirty-Ninth Supplemental Indenture dated as of January 4, 2013, to the U.S. Bank Indenture and Form of 4.875% Prospect Capital InterNote® due 2031(30)
(d)(38)	Fortieth Supplemental Indenture dated as of January 4, 2013, to the U.S. Bank Indenture and Form of 5.875% Prospect Capital InterNote® due 2043(30)
(d)(39)	Forty-First Supplemental Indenture dated as of January 10, 2013, to the U.S. Bank Indenture and Form of 4.250% Prospect Capital InterNote® due 2020(31)
(d)(40)	Forty-Second Supplemental Indenture dated as of January 10, 2013, to the U.S. Bank Indenture and Form of 4.750% Prospect Capital InterNote® due 2031(31)
(d)(41)	Forty-Third Supplemental Indenture dated as of January 10, 2013, to the U.S. Bank Indenture and Form of 5.750% Prospect Capital InterNote® due 2043(31)
(d)(42)	Forty-Fourth Supplemental Indenture dated as of January 17, 2013, to the U.S. Bank Indenture and Form of 4.125% Prospect Capital InterNote® due 2020(32)
(d)(43)	Forty-Fifth Supplemental Indenture dated as of January 17, 2013, to the U.S. Bank Indenture and Form of 4.625% Prospect Capital InterNote® due 2031(32)
(d)(44)	Forty-Sixth Supplemental Indenture dated as of January 17, 2013, to the U.S. Bank Indenture and Form of 5.625% Prospect Capital InterNote® due 2043(32)
(d)(45)	Forty-Seventh Supplemental Indenture dated as of January 25, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(33)
(d)(46)	Forty-Eighth Supplemental Indenture dated as of January 25, 2013, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2031(33)
(d)(47)	Forty-Ninth Supplemental Indenture dated as of January 25, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(33)
(d)(48)	Fiftieth Supplemental Indenture dated as of January 31, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(34)
(d)(49)	Fifty-First Supplemental Indenture dated as of January 31, 2013, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2031(34)
(d)(50)	Fifty-Second Supplemental Indenture dated as of January 31, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(34)
(d)(51)	Fifty-Third Supplemental Indenture dated as of February 7, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(35)
(d)(52)	Fifty-Fourth Supplemental Indenture dated as of February 7, 2013, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2031(35)
(d)(53)	Fifty-Fifth Supplemental Indenture dated as of February 7, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(35)

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- (d)(54) Fifty-Sixth Supplemental Indenture dated as of February 22, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(36)
- (d)(55) Fifty-Seventh Supplemental Indenture dated as of February 22, 2013, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2031(36)
- (d)(56) Fifty-Eighth Supplemental Indenture dated as of February 22, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(36)

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Exhibit No.	Description
(d)(57)	Fifty-Ninth Supplemental Indenture dated as of February 28, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(37)
(d)(58)	Sixtieth Supplemental Indenture dated as of February 28, 2013, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2031(37)
(d)(59)	Sixty-First Supplemental Indenture dated as of February 28, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(37)
(d)(60)	Sixty-Second Supplemental Indenture dated as of March 7, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(38)
(d)(61)	Sixty-Third Supplemental Indenture dated as of March 7, 2013, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2031(38)
(d)(62)	Sixty-Fourth Supplemental Indenture dated as of March 7, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(38)
(d)(63)	Sixty-Fifth Supplemental Indenture dated as of March 14, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(39)
(d)(64)	Sixty-Sixth Supplemental Indenture dated as of March 14, 2013, to the U.S. Bank Indenture and Form of 4.125% to 6.000% Prospect Capital InterNote® due 2031(39)
(d)(65)	Sixty-Seventh Supplemental Indenture dated as of March 14, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(39)
(d)(66)	Sixty-Eighth Supplemental Indenture dated as of March 14, 2013, to the U.S. Bank Indenture and Form of Floating Prospect Capital InterNote® due 2023(39)
(d)(67)	Supplemental Indenture dated as of March 15, 2013, to the U.S. Bank Indenture(40)
(d)(68)	Form of Global Note 5.875% Senior Note due 2023(41)
(d)(69)	Sixty-Ninth Supplemental Indenture dated as of March 21, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(42)
(d)(70)	Seventieth Supplemental Indenture dated as of March 21, 2013, to the U.S. Bank Indenture and Form of 4.125% to 6.000% Prospect Capital InterNote® due 2031(42)
(d)(71)	Seventy-First Supplemental Indenture dated as of March 21, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(42)
(d)(72)	Seventy-Second Supplemental Indenture dated as of March 21, 2013, to the U.S. Bank Indenture and Form of Floating Prospect Capital InterNote® due 2023(42)
(d)(73)	Seventy-Third Supplemental Indenture dated as of March 28, 2013, to the U.S. Bank Indenture and Form of 4.000% Prospect Capital InterNote® due 2020(43)
(d)(74)	Seventy-Fourth Supplemental Indenture dated as of March 28, 2013, to the U.S. Bank Indenture and Form of 4.125% to 6.000% Prospect Capital InterNote® due 2031(43)
(d)(75)	Seventy-Fifth Supplemental Indenture dated as of March 28, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2043(43)
(d)(76)	Seventy-Sixth Supplemental Indenture dated as of March 28, 2013, to the U.S. Bank Indenture and Form of Floating Prospect Capital InterNote® due 2023(43)
(d)(77)	Seventy-Seventh Supplemental Indenture dated as of April 4, 2013, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2020(44)
(d)(78)	Seventy-Eighth Supplemental Indenture dated as of April 4, 2013, to the U.S. Bank Indenture and Form of 4.625% to 6.500% Prospect Capital InterNote® due 2031(44)
(d)(79)	Seventy-Ninth Supplemental Indenture dated as of April 4, 2013, to the U.S. Bank Indenture and Form of 6.000% Prospect Capital InterNote® due 2043(44)
(d)(80)	Eightieth Supplemental Indenture dated as of April 4, 2013, to the U.S. Bank Indenture and Form of Floating Prospect Capital InterNote® due 2023(44)
(d)(81)	Eighty-First Supplemental Indenture dated as of April 11, 2013, to the U.S. Bank Indenture and Form of 4.500% Prospect Capital InterNote® due 2020(45)

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- (d)(82) Eighty-Second Supplemental Indenture dated as of April 11, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2031(45)
- (d)(83) Eighty-Third Supplemental Indenture dated as of April 11, 2013, to the U.S. Bank Indenture and Form of 6.000% Prospect Capital InterNote® due 2043(45)
- (d)(84) Eighty-Fourth Supplemental Indenture dated as of April 11, 2013, to the U.S. Bank Indenture and Form of Floating Prospect Capital InterNote® due 2023(45)

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Exhibit No.	Description
(d)(85)	Eighty-Fifth Supplemental Indenture dated as of April 18, 2013, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2020(46)
(d)(86)	Eighty-Sixth Supplemental Indenture dated as of April 18, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2031(46)
(d)(87)	Eighty-Seventh Supplemental Indenture dated as of April 18, 2013, to the U.S. Bank Indenture and Form of 6.000% Prospect Capital InterNote® due 2043(46)
(d)(88)	Eighty-Eighth Supplemental Indenture dated as of April 25, 2013, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2020(47)
(d)(89)	Eighty-Ninth Supplemental Indenture dated as of April 25, 2013, to the U.S. Bank Indenture and Form of 5.500% Prospect Capital InterNote® due 2031(47)
(d)(90)	Ninetieth Supplemental Indenture dated as of April 25, 2013, to the U.S. Bank Indenture and Form of 6.000% Prospect Capital InterNote® due 2043(47)
(d)(91)	Ninety-First Supplemental Indenture dated as of May 2, 2013, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2020(48)
(d)(92)	Ninety-Second Supplemental Indenture dated as of May 2, 2013, to the U.S. Bank Indenture and Form of 5.750% Prospect Capital InterNote® due 2031(48)
(d)(93)	Ninety-Third Supplemental Indenture dated as of May 2, 2013, to the U.S. Bank Indenture and Form of 6.250% Prospect Capital InterNote® due 2043(48)
(d)(94)	Ninety-Fourth Supplemental Indenture dated as of May 9, 2013, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2020(49)
(d)(95)	Ninety-Fifth Supplemental Indenture dated as of May 9, 2013, to the U.S. Bank Indenture and Form of 5.750% Prospect Capital InterNote® due 2031(49)
(d)(96)	Ninety-Sixth Supplemental Indenture dated as of May 9, 2013, to the U.S. Bank Indenture and Form of 6.250% Prospect Capital InterNote® due 2043(49)

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(d)(97)	Ninety-Seventh Supplemental Indenture dated as of May 23, 2013, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2020(50)			
(d)(98)	Ninety-Eighth Supplemental Indenture dated as of May 23, 2013, to the U.S. Bank Indenture and Form of 5.750% Prospect Capital InterNote® due 2031(50)			
(d)(99)	Ninety-Ninth Supplemental Indenture dated as of May 23, 2013, to the U.S. Bank Indenture and Form of 6.250% Prospect Capital InterNote® due 2043(50)			
(d)(100)	One Hundredth Supplemental Indenture dated as of May 23, 2013, to the U.S. Bank Indenture and Form of 5.000% to 7.000% Prospect Capital InterNote® due 2028(50)			
(d)(101)	One Hundred-First Supplemental Indenture dated as of May 31, 2013, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2020(51)			
(d)(102)	One Hundred-Second Supplemental Indenture dated as of May 31, 2013, to the U.S. Bank Indenture and Form of 5.750% Prospect Capital InterNote® due 2031(51)			
(d)(103)	One Hundred-Third Supplemental Indenture dated as of May 31, 2013, to the U.S. Bank Indenture and Form of 6.250% Prospect Capital InterNote® due 2043(51)			
(d)(104)	One Hundred-Fourth Supplemental Indenture dated as of June 6, 2013, to the U.S. Bank Indenture and Form of 5.000% Prospect Capital InterNote® due 2020(52)			
(d)(105)	One Hundred-Fifth Supplemental Indenture dated as of June 6, 2013, to the U.S. Bank Indenture and Form of 5.750% Prospect Capital InterNote® due 2031(52)			
(d)(106)	One Hundred-Sixth Supplemental Indenture dated as of June 6, 2013, to the U.S. Bank Indenture and Form of 6.250% Prospect Capital InterNote® due 2043(52)			
(d)(107)	(27,711)	(30,801)	(55,611)	(64,820)
TRUST				
CORPUS: End \$	349,237	\$ 456,415	\$ 349,237	\$ 456,415
of period				

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 95% of the Producing Wells and the completed Development Wells and expects to operate approximately 88% of the remaining Development Wells.

The business and affairs of the Trust are managed by the Trustee. The Trust Agreement limits the Trust's business activities generally to owning the Royalty Interests and any activity reasonably related to such ownership, including activities required or permitted by the terms of the conveyances related to the Royalty Interests and derivative contracts between the Trust and its counterparty. The royalty 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 liquids ("NGL") and natural gas 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, NGL and natural gas production attributable to Chesapeake's net revenue interest in the Development Wells.

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

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

distributions equal to 50% of the amount by which the cash available for distribution on all of the Trust units in any quarter is 20% greater than the target distribution for such quarter (the “incentive threshold”). The remaining 50% of cash available for distribution in excess of the applicable incentive threshold will be paid to Trust unitholders, including Chesapeake, on a pro rata basis. At the end of the fourth full calendar quarter following Chesapeake’s satisfaction of its drilling obligation with respect to the Development Wells, the subordinated units will automatically convert into common units

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

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 distributable income for the production period from December 1, 2012 to February 28, 2013 and the production period from September 1, 2012 to November 30, 2012 was, in each case, below the subordination threshold. As a result, the distributions paid in the three months ended June 30, 2013 and the three months ended March 31, 2013 were \$0.6900 per common unit and \$0.3010 per subordinated unit and \$0.6700 per common unit and \$0.3772 per subordinated unit, respectively. All of the subordinated units are held by Chesapeake. See 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, 2012, which has been derived from audited financial statements, and the unaudited interim financial statements of the Trust as of, or for the three and six months ended, June 30, 2013 and June 30, 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, 2012 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, 2012.

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

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

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

Risks and Uncertainties. The Trust's revenue and distributions are substantially dependent upon the prevailing and future prices for oil, NGL and natural gas, each of which depends on numerous factors beyond the Trust's control such as economic conditions, regulatory developments and competition from other energy sources. Oil, NGL and natural gas prices historically have been volatile, and may be subject to significant fluctuations in the future. The Trust's

derivative contracts serve to mitigate the effect of this price volatility on a portion of the Trust's anticipated oil and NGL production through September 30, 2015. See Note 3 for the Trust's derivative contracts.

Low natural gas prices combined with stronger oil prices have resulted in an industry-wide increase in drilling activity in oil- and NGL-rich plays. The resulting increase in production volumes of NGL led to a significant decrease

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in the price of NGL in both absolute terms and on a relative basis compared to oil. The Trust's exposure to low prices for NGL and reduced production volumes for the production periods from September 1, 2012 to May 31, 2013, in addition to higher than expected pressure depletion within the AMI described below, resulted in per unit income available for distribution below the applicable subordination threshold. Accordingly, the Trust paid a common unit distribution at the subordination threshold of \$0.6900 and a subordinated unit distribution of \$0.3010 on May 31, 2013, covering production from December 1, 2012 through February 28, 2013, and a common unit distribution at the subordination threshold of \$0.6700 and a subordinated unit distribution of \$0.3772 on March 1, 2013, covering production from September 1, 2012 through November 30, 2012 and, on August 8, 2013, the Trust announced that, on or about August 29, 2013, it will pay a common unit distribution at the subordination threshold of \$0.6900 and a subordinated unit distribution of \$0.1432, covering production from March 1, 2013 to May 31, 2013, to record unitholders as of August 19, 2013. Sustained low commodity prices and higher than expected pressure depletion have reduced and may continue to reduce the Trust's revenues and distributable income available to unitholders, which may contribute to future distributions to common unitholders below the subordination threshold, and could lead to future impairments.

For the three months ended June 30, 2013 and March 31, 2013, the Trust recognized an \$11.4 million and a \$32.9 million impairment of the Royalty Interests, for each period, primarily due to higher than expected pressure depletion within certain areas of the AMI which has resulted in lower initial production rates and lower expected ultimate recovery in certain recent Development Wells. See Investment in Royalty Interests below for further discussion of the impairments. Chesapeake has informed the Trust that it is currently performing additional testing and scientific analysis of the Colony Granite Wash reservoir in an effort to potentially enhance the value of the remaining Development Wells by optimizing well spacing and Colony Granite Wash interval selections. Chesapeake has also advised that it believes it is prudent to reduce its operated rig count in the AMI from four rigs to two rigs beginning in mid-August 2013, which will allow more time to apply well performance analysis from well to well as Chesapeake's drilling program progresses at a slower pace. At this time, Chesapeake is unable to predict how long its operated rig count will remain at two rigs or the outcome of its additional testing and analysis, including any potential improvement in Development Well drilling performance or the potential effects on future distributions to common unitholders. If well performance does not improve, the Trust's revenues and distributable income available to unitholders will be reduced, which may contribute to future distributions to common unitholders below the subordination threshold, and decreased well performance or lower expected ultimate recovery may also lead to further impairments. In addition, the operated rig count reduction from four rigs to two rigs will decrease the rate at which royalty income from the remaining Development Wells becomes available to the Trust for distribution to unitholders, which, if combined with continued low NGL and natural gas prices and reduced well performance, will likely result in future distributions to common unitholders below the subordination threshold beginning in 2014. If a quarterly cash distribution in respect of the common units is lower than the applicable subordination threshold, the common units will not be entitled to receive any additional distributions nor will the units be entitled to arrearages in any future quarter.

Chesapeake'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, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on a drilling support lien (the "Drilling Support Lien") to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect 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 in a foreclosure or other action was limited to approximately \$102.2 million as of June 30, 2013 and further reduced to \$96.6 million as of August 2, 2013. The

maximum amount that may be recovered under the Drilling Support Lien will decrease as the remaining Development Wells are drilled and completed.

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

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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.

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

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

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

On a quarterly basis, the Trust evaluates the carrying value of the Investment in Royalty Interests under the full cost accounting method prescribed by the SEC. This quarterly review is referred to as a ceiling test. Under the ceiling test, the carrying value of the Investment in Royalty Interests may not exceed an amount equal to the sum of the present value (using a 10% discount rate) of the estimated future net revenues from proved reserves. For the three months ended June 30, 2013 and March 31, 2013, the carrying value of the Investment in Royalty Interests exceeded the estimated present value calculation of future net revenues from proved reserves, resulting in an \$11.4 million and a \$32.9 million impairment, for each period, in the carrying value of the Investment in Royalty Interests. The impairments were the result of reserve revisions attributable to current results being below expectations, primarily caused by higher than expected pressure depletion within certain areas of the AMI. This has resulted in lower initial production rates and lower expected ultimate recovery in certain recent Development Wells. The impairments resulted in non-cash charges to the Trust corpus and did not affect the Trust distributable income. See Risks and Uncertainties above for further discussion.

Derivatives. To mitigate a portion of the exposure to adverse market changes of oil prices and, to the extent oil production falls below the hedged oil volume, NGL prices, the Trust is party to derivative contracts with its hedge counterparty. See Note 3 for discussion of the derivative contracts currently outstanding.

The Trust records gains or losses from the derivative contracts when proceeds are received or payments are made, respectively. Additionally, changes in the fair value of the derivative contracts are accounted for as an adjustment to Trust corpus and the fair value carried on the statement of assets, liabilities and trust corpus. Cash distributions to unitholders will be increased or decreased by the effect of the Trust's derivative contracts.

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. A loan neither increases nor decreases distributions to unitholders; however, 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 June 30, 2013 or December 31, 2012.

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, NGL and natural

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

3. Derivative Contracts

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

The Trust's obligations to the counterparty under the derivative contracts are secured by liens on proved reserves attributable to the Trust's interest in the Underlying Properties. The counterparty's obligations under the hedge 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 exceed the defined thresholds. Mark-to-market amounts did not exceed the defined thresholds as of June 30, 2013.

As of June 30, 2013, the Trust had the following oil derivative contracts:

Production Quarter	Fixed-Price Oil Swaps		
	Volume (mdbl)	Weighted Avg. Price (per bbl)	Fair Value Asset/(Liability) (\$ in thousands)
Q1 2013 ⁽¹⁾	61.3	\$87.54	\$(352)
Q2 2013 ⁽²⁾	184.3	\$87.60	(1,205)
Q3 2013	187.9	\$87.79	(1,504)
Q4 2013	184.2	\$87.99	(1,145)
Q1 2014	179.8	\$88.08	(729)
Q2 2014	180.3	\$88.21	(417)
Q3 2014	178.8	\$88.34	(158)
Q4 2014	174.3	\$88.45	75
Q1 2015	171.0	\$88.59	295
Q2 2015	175.4	\$88.76	477
Q3 2015	153.6	\$88.90	587
Total	1,830.9	\$88.23	\$(4,076)

(1)Includes March 2013 production that was settled in August 2013.

(2)Includes April and May 2013 production that was settled in August 2013.

To the extent expected oil production falls below the hedged oil volume, the derivative contracts will also cover expected NGL production. Such estimated production of NGL is hedged with oil contracts using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. In 2012 and continuing in 2013, NGL prices decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the derivative contracts will not effectively mitigate the price risk of the Trust's NGL production.

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Additional Disclosures Regarding Derivative Contracts

In accordance with accounting guidance for derivatives and hedging, and because a legal right of set-off exists, the Trust has netted the value of its derivative contracts with the counterparty in the accompanying statement of assets, liabilities and trust corpus. Short-term derivative liability represents the estimated fair value of derivatives scheduled to settle in cash over the next twelve months based on market prices as of June 30, 2013. The Trust does 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 are accounted for as an adjustment to Trust corpus. Results of settled derivative contracts are reflected in distributable income in the period when paid. For the three months ended June 30, 2013 and June 30, 2012, the Trust settled derivative contracts that resulted in a payment to the counterparty of \$1.0 million and \$2.6 million, respectively. For the six months ended June 30, 2013 and June 30, 2012, the Trust settled derivative contracts that resulted in payments to the counterparty, in the aggregate, of \$1.6 million and \$3.4 million, respectively. The following table presents the fair value and location of each classification of derivative contracts disclosed in the statements of assets, liabilities and trust corpus as of June 30, 2013 and December 31, 2012 on a gross basis without regard to same-counterparty netting:

	Statement of Assets, Liabilities and Trust Corpus Location	Fair Value	
		June 30, 2013	December 31, 2012
		(\$ in thousands)	
Asset Derivatives:			
Not designated as hedging instrument			
Commodity contracts	Short-term derivative asset	\$—	\$212
Commodity contracts	Long-term derivative asset	2,093	411
Total		\$2,093	\$623
Liability Derivatives:			
Not designated as hedging instrument			
Commodity contracts	Short-term derivative liability	\$(4,762)	\$(3,488)
Commodity contracts	Long-term derivative liability	(1,407)	(5,219)
Total		(6,169)	(8,707)
Total derivatives instruments		\$(4,076)	\$(8,084)

All of the Trust's derivative positions are 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 do not have restrictions. Under such netting arrangements, the Trust offsets the fair value of derivative instruments with cash collateral received or paid for those contracts executed with the same counterparty, which reduces the Trust's total assets and Trust corpus. As of June 30, 2013 and December 31, 2012, the Trust did not have any cash collateral balances for these derivatives.

The following tables present the netting offsets of derivative assets and liabilities as of June 30, 2013 and December 31, 2012.

	June 30, 2013		Derivative Liabilities	
	Derivative Assets			
	Short-term	Long-Term	Short-term	Long-Term
(\$ in thousands)				
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	\$—	\$2,093	\$(4,762)	\$(1,407)

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Gross amounts offset in the statement of assets, liabilities and trust corpus	—	(1,407) —	1,407
Total derivatives as reported	\$—	\$686	\$(4,762) \$—

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	December 31, 2012		Derivative Liabilities	
	Derivative Assets		Short-term	Long-Term
	Short-term	Long-Term	Short-term	Long-Term
	(\$ in thousands)			
Commodity Contracts:				
Gross amounts of recognized assets (liabilities)	\$212	\$411	\$(3,488)	\$(5,219)
Gross amounts offset in the statement of assets, liabilities and trust corpus	(212)	(411)	212	411
Total derivatives as reported	\$—	\$—	\$(3,276)	\$(4,808)

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.

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 derivative contracts and the administrative services agreement. Moreover, the Trust will indemnify Chesapeake for any actions it takes in this regard.

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

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

In drilling the Development Wells, Chesapeake is required to act diligently and as a reasonably prudent oil and gas operator would act under the same or similar circumstances as if it were acting with respect to its own properties, disregarding the existence of the Royalty Interests as burdens affecting such properties (the "Reasonably Prudent Operator Standard"). Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells, the existing Development Wells and other Colony Granite Wash producing wells outside of the AMI.

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

A wholly owned subsidiary of Chesapeake has granted to the Trust the Drilling Support Lien covering Chesapeake's retained interest in the AMI (except its interest in the Producing Wells, Development Wells and any other wells not subject to the Royalty Interests) in order to secure the estimated amount of the drilling costs for the Trust's interests in the Development Wells. The maximum amount that may be obtained by the Trust pursuant to the Drilling Support Lien initially could not exceed \$262.7 million. As Chesapeake fulfills its drilling obligation over time, the total amount that may be recovered is proportionately reduced and completed Development Wells are 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 August 2, 2013, Chesapeake had drilled and completed, or caused to be drilled or completed, a total of 68 wells in the AMI (approximately 74.6 Development Wells as calculated under the development agreement), reducing the amount that may be recovered under the Drilling Support Lien to approximately \$96.6 million. See Risks and Uncertainties in Note 2 regarding Chesapeake's plan to reduce its operated rig count from four rigs to two rigs in connection with testing and analysis it is conducting related to future Development Well drilling.

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 June 30, 2013 or December 31, 2012.

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6. Fair Value Measurement

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

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

The following table provides fair value measurement information for financial assets (liabilities) measured at fair value on a recurring basis as of June 30, 2013:

	Quoted Prices in Active Markets (Level 1) (\$ in thousands)	Significant Other Observable Inputs (Level 2)	Significant Unobservable Inputs (Level 3)	Total Fair Value
Financial Assets (Liabilities):				
Derivative assets	\$—	\$686	\$—	\$686
Derivative liabilities	—	(4,762) —	(4,762)
Total	\$—	\$(4,076) \$—	\$(4,076)

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

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

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

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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.

For the six months ended June 30, 2013 and June 30, 2012, the Trust declared and paid the following cash distributions:

Production Period	Distribution Date	Cash Distribution per Common Unit	Cash Distribution per Subordinated Unit
December 2012 - February 2013	May 31, 2013	\$0.6900	\$0.3010
September 2012 - November 2012	March 1, 2013	\$0.6700	\$0.3772
December 2011 - February 2012	May 31, 2012	\$0.6588	\$0.6588
September 2011 - November 2011	March 1, 2012	\$0.7277	\$0.7277

8. Subsequent Events

On August 8, 2013, the Trust declared a cash distribution of \$0.6900 per common unit and \$0.1432 per subordinated unit, consisting of proceeds attributable to production from March 1, 2013 to May 31, 2013, to record unitholders as of August 19, 2013. The distribution will be paid on August 29, 2013. The Trust's quarterly income available for distribution was \$0.5533 per unit, which was \$0.1367 below the subordination threshold. As a result, the distribution per common unit will be the subordination threshold of \$0.6900 for the quarter. Distributable income attributable to production from March 1, 2013 to May 31, 2013 was calculated as follows (in thousands except for unit and per unit amounts):

REVENUES:

Royalty income ⁽¹⁾	\$27,759
Total Revenues	27,759

EXPENSES:

Production taxes	497
Trust administrative expenses ⁽²⁾	342
Derivative settlement loss	1,053
Total Expenses	1,892
Distributable income available to unitholders	\$25,867

Distributable income per common unit (35,062,500 units)	\$0.6900
Distributable income per subordinated unit (11,687,500 units)	\$0.1432

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

Beginning in mid-August 2013, Chesapeake intends to reduce its operated rig count in the AMI from four rigs to two. See Risks and Uncertainties in Note 2 for further discussion.

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, 2012 (the "2012 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 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 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 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 June 30, 2013, Chesapeake had drilled and completed 65 wells within the AMI (approximately 72.1 Development Wells as calculated under the development agreement). As of August 2, 2013, Chesapeake had drilled and completed, or caused to be drilled and completed, a total of 68 wells within the AMI (approximately 74.6 Development Wells as calculated under the development agreement).

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

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

On November 16, 2011, Chesapeake novated to the Trust, and the Trust became party to, derivative contracts covering a portion of the production attributable to the Royalty Interests from October 1, 2011 through September 30, 2015. The Trust's distributable income will include net settlements under these derivative contracts. The value of the derivative contracts as of June 30, 2013 was a net liability of \$4.1 million.

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. The distribution made in the first quarter of 2013, consisting of proceeds attributable to production from September 1, 2012 through November 30, 2012, was made on March 1, 2013

to record unitholders as of February 19, 2013. The distribution made in the second quarter of 2013, consisting of proceeds attributable to production from December 1, 2012 through February 28, 2013, was made on May 31, 2013 to record unitholders as of May 21, 2013.

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

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

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

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

At the end of the 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 (per unit)	Incentive Threshold
2013:		
First Quarter ⁽¹⁾	\$0.69	\$1.04
Second Quarter ⁽²⁾	\$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 \$0.6900 per common unit and \$0.3010 per subordinated unit was made on May 31, 2013 to unitholders of record as of May 21, 2013.

(2) A distribution of \$0.6900 per common unit and \$0.1432 per subordinated unit was declared on August 8, 2013 and will be paid on or about August 29, 2013 to unitholders of record as of August 19, 2013.

Results of Trust Operations

The quarterly payments to the Trust with respect to the Royalty Interests are based on the amount of proceeds actually received by Chesapeake during the preceding calendar quarter. Proceeds from production are typically received by Chesapeake one month after production. Due to the timing of the payment of production proceeds, quarterly distributions made by Chesapeake to the Trust will generally include royalties attributable to sales of oil, NGL and natural gas for three months, comprised of the first two months of the quarter just ended and the last month of the quarter prior to that one. Chesapeake is required to make the Royalty Interest payments to the Trust within 35 days of the end of each calendar quarter. As a result, in May 2013, the Trust received a payment on the Royalty Interests representing royalties attributable to proceeds from sales of oil, NGL and natural gas for December 1, 2012 through February 28, 2013. In March 2013, the Trust received a payment on the Royalty Interests representing royalties attributable to proceeds from sales of oil, NGL and natural gas for September 1, 2012 through November 30, 2012.

Low natural gas prices combined with stronger oil prices have resulted in an industry-wide increase in drilling activity in oil- and NGL-rich plays. The resulting increase in production volumes of NGL led to a significant decrease in the price of NGL in both absolute terms and on a relative basis compared to oil. The Trust's exposure to low prices for NGL and reduced production volumes for the production periods from September 1, 2012 to May 31, 2013, in addition to higher than expected pressure depletion within the AMI described below, resulted in per unit income available for distribution below the applicable subordination threshold. Accordingly, the Trust paid a common unit distribution at the subordination threshold of \$0.6900 and a subordinated unit distribution of \$0.3010 on May 31, 2013, covering production from December 1, 2012 through February 28, 2013, and a common unit distribution at the subordination threshold of \$0.6700 and a subordinated unit distribution of \$0.3772 on March 1, 2013, covering production from September 1, 2012 through November 30, 2012 and, on August 8, 2013, the Trust announced that, on or about August 29, 2013, it will pay a common unit distribution at the subordination threshold of \$0.6900 and a subordinated unit distribution of \$0.1432, covering production from March 1, 2013 to May 31, 2013, to record unitholders as of August 19, 2013. Sustained low commodity prices and higher than expected pressure depletion have reduced and may continue to reduce the Trust's revenues and distributable income available to unitholders, which may contribute to future distributions to common unitholders below the subordination threshold, and could lead to future impairments.

For the three months ended June 30, 2013 and March 31, 2013, the Trust recognized an \$11.4 million and a \$32.9 million impairment of the Royalty Interests, for each period, primarily due to higher than expected pressure depletion within certain areas of the AMI which has resulted in lower initial production rates and lower expected ultimate recovery in certain recent Development Wells. See Risks and Uncertainties in Note 2 for further discussion. Chesapeake has informed the Trust that it is currently performing additional testing and scientific analysis of the Colony Granite Wash reservoir in an effort to potentially enhance the value of the remaining Development Wells by optimizing well spacing and Colony Granite Wash interval selections. Chesapeake has also advised that it believes it is prudent to reduce its operated rig count in the AMI from four rigs to two rigs beginning in mid-August 2013, which will allow more time to apply well performance analysis from well to well as Chesapeake's drilling program progresses at a slower pace. At this time, Chesapeake is unable to predict how long its operated rig count will remain at two rigs or the outcome of its additional testing and analysis, including any potential improvement in Development Well drilling performance or the potential effects on future distributions to common unitholders. If well performance does not improve, the Trust's revenues and distributable income available to unitholders will be reduced, which may contribute to future distributions to common unitholders below the subordination threshold, and decreased well performance or lower expected ultimate recovery may also lead to further impairments. In addition, the operated rig count reduction from four rigs to two rigs will decrease the rate at which royalty income from the remaining Development Wells becomes available to the Trust for distribution to unitholders, which, if combined with continued low NGL and natural gas prices and reduced well performance, will likely result in future distributions to common unitholders below the subordination threshold beginning in 2014. If a quarterly cash distribution in respect of the common units is lower than the applicable subordination threshold, the common units will not be entitled to receive any additional distributions nor will the units be entitled to arrearages in any future quarter.

Trust Operations for the Three Months Ended June 30, 2013 as compared to June 30, 2012.

Distributable Income. The Trust's distributable income was \$27.7 million for the three months ended June 30, 2013 compared to \$30.8 million for the three months ended June 30, 2012, a decrease of \$3.1 million. This decrease was primarily due to the decrease in the average realized prices received from sales of oil and NGL and lower than expected initial production rates from Development Wells completed in the production period from December 1, 2012 to February 28, 2013 ("current production quarter"). During the current production quarter, the average price received for oil was \$88.08 per barrel ("bbl") compared to \$97.03 per bbl for the production period from December 1, 2011 to February 29, 2012 ("prior production quarter"). NGL prices received were \$32.67 per bbl for the current production quarter compared to \$36.56 per bbl for the prior production quarter. Current production quarter oil sales volumes also decreased from the prior production quarter to 149 thousand barrels ("mbbls") from 182 mbbls due to higher than expected pressure depletion within certain areas of the AMI. These decreases were offset by an increase in the price received for natural gas to \$2.28 per thousand cubic feet ("mcf") for the current production quarter from \$1.90 per mcf

for the prior production quarter.

On a per unit basis, cash distributions during the three months ended June 30, 2013 and attributable to the current production quarter were \$0.6900 per common unit and \$0.3010 per subordinated unit as compared to \$0.6588 per common and subordinated unit for the three months ended June 30, 2012 and attributable to the prior production quarter. Distributable income for the three months ended June 30, 2013, and attributable to the current production quarter, and the three months ended June 30, 2012, and attributable to the prior production quarter, was calculated as follows:

	Three Months Ended June 30,	
	2013	2012
	(\$ in thousands, except per unit data)	
Revenues:		
Royalty income ⁽¹⁾	\$29,868	\$34,554
Interest income	—	1
Total Revenues	\$29,868	\$34,555
Expenses:		
Production taxes	\$577	\$798
Trust administrative expenses ⁽²⁾	573	389
Derivative settlement loss	1,007	2,567
Total Expenses	2,157	3,754
Distributable income available to unitholders	\$27,711	\$30,801
Distributable income per common unit (35,062,500 units issued and outstanding)	\$0.6900	\$0.6588
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	\$0.3010	\$0.6588

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

Royalty Income. Royalty income to the Trust for the three months ended June 30, 2013, and attributable to the current production quarter, totaled \$29.9 million based upon sales of production attributable to the Royalty Interests of 149 mbbbls of oil, 312 mbbbls of NGL and 2,886 million cubic feet ("mmcf") of natural gas. Total production for the current production quarter was 942 thousand barrels of oil equivalent ("mboe"). Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the current production quarter were \$88.08 per bbl, \$32.67 per bbl and \$2.28 per mcf, respectively.

Royalty income to the Trust for the three months ended June 30, 2012, and attributable to the prior production quarter, totaled \$34.5 million based upon sales of production attributable to the Royalty Interests of 182 mbbbls of oil, 315 mbbbls of NGL and 2,921 mmcf of natural gas. Total production for the prior production quarter was 984 mboe.

Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the prior production quarter were \$97.03 per bbl, \$36.56 per bbl and \$1.90 per mcf, respectively.

Production Taxes. Production taxes are calculated as a percentage of oil, NGL and natural gas revenues, net of any applicable tax credits. Production taxes for the three months ended June 30, 2013, and attributable to the current production quarter, totaled \$0.6 million, or \$0.61 per barrel of oil equivalent ("boe") as compared to production taxes for the three months ended June 30, 2012 and attributable to the prior production quarter, which totaled \$0.8 million, or \$0.81 per boe. In both periods, production taxes were approximately 2% of royalty income.

Trust Administrative Expenses. Trust administrative expenses, including additional cash reserves, for the three months ended June 30, 2013 totaled \$0.6 million as compared to \$0.4 million for the three months ended June 30, 2012. Trust administrative expenses primarily consist of the administrative fees paid to the Trustees and Chesapeake and costs for accounting and legal services.

Derivative Settlement Loss. The Trust records gains or losses from the derivative contracts when proceeds are received or payments are made, respectively. Swaps covering the current production quarter were settled, during the three months ended June 30, 2013, with proceeds from royalty income for the current production quarter. Total losses during the three months ended June 30, 2013 were \$1.0 million. Swaps covering the prior production quarter were settled, during the three months ended June 30, 2012, with proceeds from royalty income for the prior production quarter. Total losses during the three months ended June 30, 2012 were \$2.6 million.

Development Wells. As of June 30, 2013, all of the Producing Wells were producing and approximately 72.1 Development Wells (as calculated under the development agreement) were completed and producing. The amount that could be recovered under the Drilling Support Lien as of June 30, 2013 was approximately \$102.2 million. In addition, 2.5 Development Wells (as calculated under the development agreement) were drilled in the AMI and subsequently completed in July 2013. As of August 2, 2013, Chesapeake had drilled and completed, or caused to be drilled and completed, a total of 68 wells within the AMI (approximately 74.6 Development Wells as calculated under the development agreement) and the amount that could be recovered under the Drilling Support Lien was approximately \$96.6 million.

Impairment of Royalty Interests. During the quarter ended June 30, 2013, the Trust recognized an \$11.4 million impairment of the Royalty Interests. The impairment was the result of reserve revisions attributable to current production being below expectations, primarily as a result of higher than expected pressure depletion within certain areas of the AMI. This has resulted in lower initial production rates and lower expected ultimate recovery in certain recent development wells. The impairment resulted in a non-cash charge to the Trust corpus and did not affect the Trust's distributable income. See Risks and Uncertainties in Note 2 in Item I of Part I.

Trust Operations for the Six Months Ended June 30, 2013 as compared to June 30, 2012.

Distributable Income. The Trust's distributable income was \$55.6 million for the six months ended June 30, 2013 compared to \$64.8 million for the six months ended June 30, 2012, a decrease of \$9.2 million. This decrease was primarily due to the decrease in the average realized prices received from sales of oil, NGL and natural gas and lower than expected initial production rates from Development Wells completed in the production period from September 1, 2012 to February 28, 2013 ("current production period"). During the current production period, the average price received for oil was \$87.16 per bbl compared to \$91.68 per bbl for the production period from September 1, 2011 to February 29, 2012 ("prior production period"). NGL prices received were \$32.29 per bbl for the current production period compared to \$39.72 per bbl for the prior production period. Natural gas prices were \$2.10 per mcf for the current production period compared to \$2.26 per mcf for the prior production period.

On a per unit basis, cash distributions during the six months ended June 30, 2013 and attributable to the current production period were \$1.3600 per common unit and \$0.6782 per subordinated unit as compared to \$1.3865 per common and subordinated unit for the six months ended June 30, 2012 and attributable to the prior production period. Distributable income for the six months ended June 30, 2013, and attributable to the current production period, and the six months ended June 30, 2012, and attributable to prior production period, was calculated as follows:

	Six Months Ended June 30,	
	2013	2012
	(\$ in thousands, except per unit data)	
Revenues:		
Royalty income ⁽¹⁾	\$59,331	\$70,624
Interest income	—	2
Total Revenues	\$59,331	\$70,626
Expenses:		
Production taxes	\$1,165	\$1,550
Trust administrative expenses ⁽²⁾	939	865
Derivative settlement loss	1,616	3,391
Total Expenses	3,720	5,806
Distributable income available to unitholders	\$55,611	\$64,820
Distributable income per common unit (35,062,500 units issued and outstanding)	\$1.3600	\$1.3865
Distributable income per subordinated unit (11,687,500 units issued and outstanding)	\$0.6782	\$1.3865

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

Royalty Income. Royalty income to the Trust for the six months ended June 30, 2013, and attributable to the current production period, totaled \$59.3 million based upon sales of production attributable to the Royalty Interests of 300 mbbbls of oil, 641 mbbbls of NGL and 5,946 mmcf of natural gas. Total production for the current production period was 1,932 mboe. Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the current production period were \$87.16 per bbl, \$32.29 per bbl and \$2.10 per mcf, respectively.

Royalty income to the Trust for the six months ended June 30, 2012, and attributable the prior production period, totaled \$70.6 million based upon sales of production attributable to the Royalty Interests of 359 mbbbls of oil, 618 mbbbls of NGL and 5,831 mmcf of natural gas. Total production for the prior production period was 1,949 mboe. Average prices received for oil, NGL and natural gas production, including the impact of certain post-production expenses and excluding production taxes, during the prior production period were \$91.68 per bbl, \$39.72 per bbl and \$2.26 per mcf, respectively.

Production Taxes. Production taxes are calculated as a percentage of oil, NGL and natural gas revenues, net of any applicable tax credits. Production taxes for the six months ended June 30, 2013 and attributable to the current production period totaled \$1.2 million, or \$0.60 per boe as compared to production taxes for the six months ended June 30, 2012 and attributable to the prior production period, which totaled \$1.6 million, or \$0.80 per boe. In both periods, production taxes were approximately 2% of royalty income.

Trust Administrative Expenses. Trust administrative expenses, including additional cash reserves, for the six months ended June 30, 2013 and June 30, 2012, respectively, totaled \$0.9 million for each period and are comparable. Trust administrative expenses primarily consist of the administrative fees paid to the Trustees and Chesapeake and costs for accounting and legal services.

Derivative Settlement Loss. The Trust records gains or losses from the derivative contracts when proceeds are received or payments are made, respectively. Swaps covering the current production period were settled, during the six months ended June 30, 2013, with proceeds from royalty income for the current production period. Total losses during the six months ended June 30, 2013 were \$1.6 million. Swaps covering the prior production period were settled, during the six months ended June 30, 2012, with proceeds from royalty income for the prior production period. Total losses during the six months ended June 30, 2012 were \$3.4 million.

Impairment of Royalty Interests. During the six months ended June 30, 2013, the Trust recognized a \$44.3 million impairment of the Royalty Interests. The impairment was the result of reserve revisions attributable to current production being below expectations, primarily as a result of higher than expected pressure depletion within certain areas of the AMI. This has resulted in lower initial production rates and lower expected ultimate recovery in certain recent development wells. The impairment resulted in a non-cash charge to the Trust corpus and did not affect the Trust's distributable income. See Risks and Uncertainties in Note 2 in Item I of Part I.

Liquidity and Capital Resources

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

The Trust is required to make quarterly cash distributions of substantially all of its cash receipts, after deducting the Trust's administrative expenses, on or about 60 days following the completion of each calendar quarter through (and including) the quarter ending June 30, 2031. During the six month period ended June 30, 2013, two distributions were paid. The current quarter distribution of \$0.6900 per common unit and \$0.3010 per subordinated unit, consisting of proceeds attributable to production from December 1, 2012 through February 28, 2013, was made on May 31, 2013 to record unitholders as of May 21, 2013. The 2013 first quarter distribution of \$0.6700 per common unit and \$0.3772 per subordinated unit, consisting of proceeds attributable to production from September 1, 2012 through November 30, 2012, was made on March 1, 2013 to record unitholders as of February 19, 2013.

On August 8, 2013, the Trust declared a cash distribution of \$0.6900 per common unit and \$0.1432 per subordinated unit, consisting of proceeds attributable to production from March 1, 2013 to May 31, 2013, to record unitholders as of August 19, 2013. The distribution will be paid on August 29, 2013. The Trust's quarterly income available for distribution was \$0.5533 per unit, which was \$0.1367 below the subordination threshold. As a result, the distribution per common unit will be the subordination threshold of \$0.6900 for the quarter. Distributable income attributable to production from March 1, 2013 to May 31, 2013 was calculated as follows (in thousands except for unit and per unit amounts):

REVENUES:	
Royalty income ⁽¹⁾	\$27,759
Total Revenues	27,759
EXPENSES:	
Production taxes	497
Trust administrative expenses ⁽²⁾	342
Derivative settlement loss	1,053
Total Expenses	1,892
Distributable income available to unitholders	\$25,867
Distributable income per common unit (35,062,500 units)	 \$0.6900
Distributable income per subordinated unit (11,687,500 units)	 \$0.1432

(1) Net of certain post-production expenses.

(2) Includes cash reserves withheld.

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. There were no loans outstanding as of June 30, 2013 or December 31, 2012.

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.

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 I of Part I of this Quarterly Report.

Critical Accounting Policies and Estimates

Refer to Note 2 in Item I of Part I 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 2012 Form 10-K.

ITEM 3. Quantitative and Qualitative Disclosures about Market Risk

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

As of June 30, 2013, the Trust had the following oil derivative contracts:

Production Quarter	Fixed-Price Oil Swaps		
	Volume (mbbl)	Weighted Avg. Price (per bbl)	Fair Value Asset/(Liability) (\$ in thousands)
Q1 2013 ⁽¹⁾	61.3	\$87.54	\$(352)
Q2 2013 ⁽²⁾	184.3	\$87.60	(1,205)
Q3 2013	187.9	\$87.79	(1,504)
Q4 2013	184.2	\$87.99	(1,145)
Q1 2014	179.8	\$88.08	(729)
Q2 2014	180.3	\$88.21	(417)
Q3 2014	178.8	\$88.34	(158)
Q4 2014	174.3	\$88.45	75
Q1 2015	171.0	\$88.59	295
Q2 2015	175.4	\$88.76	477
Q3 2015	153.6	\$88.90	587
Total	1,830.9	\$88.23	\$(4,076)

(1)Includes March 2013 production that was settled in August 2013.

(2)Includes April 2013 and May 2013 production that was settled in August 2013.

To the extent expected oil production falls below the hedged oil volume, the derivative contracts will also cover expected NGL production. Such estimated production of NGL is hedged with oil contracts using a conversion ratio of one barrel of NGL to 49.2% of a barrel of oil. In 2012 and continuing in 2013, NGL prices have decreased relative to oil prices. To the extent oil and NGL prices are not correlated, the derivative contracts will not effectively mitigate the price risk of the Trust's NGL production.

The Trust's obligations to the counterparty under the derivative contracts are secured by liens on proved reserves attributable to the Trust's interest in the Underlying Properties. The value of the derivative contracts as of June 30, 2013 was a net liability of \$4.1 million.

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

Credit Risk. A portion of the Trust's liquidity is concentrated in the derivative contracts described above. The use of oil derivative contracts exposes the Trust to credit risk from 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 and liquidity, which in turn will depend upon the supply and demand for oil, NGL and natural gas, prevailing economic conditions and financial, business and other factors, many of which are beyond Chesapeake's control.

If Chesapeake were to default on its obligation to drill the Development Wells, the Trust would be able to foreclose on the Drilling Support Lien to the extent of Chesapeake's remaining interests in the undeveloped portions of the AMI, file a lawsuit to collect money damages from Chesapeake and pursue other available legal remedies against Chesapeake. However, the Trust is not permitted to obtain specific performance from Chesapeake of its drilling obligation and the maximum amount the Trust can recover in a foreclosure or other action was limited to approximately \$96.6 million as of August 2, 2013 and will decrease as the remaining Development Wells are drilled and completed.

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

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

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. Michael J. Ulrich, as Trust Officer of the Trustee, has concluded that the disclosure controls and procedures of the Trust are effective.

Due to the nature of the Trust as a passive entity and in light of the contractual arrangements pursuant to which the Trust was created, including the provisions of (i) the Trust Agreement, (ii) the administrative services agreement, (iii) the development agreement and (iv) the conveyances granting the Royalty Interests, the Trustee’s disclosure controls and procedures related to the Trust necessarily rely on (a) information provided by Chesapeake, including information relating to results of operations, the status of drilling of the Development Wells, the costs and revenues attributable to the Trust’s interests under the conveyance and other operating and historical data, plans for future operating and capital expenditures, reserve information, information relating to projected production, and other information relating to the status and results of operations of the underlying properties and the Royalty Interests, and (b) conclusions and reports regarding reserves by the Trust’s independent reserve engineers. Other than reviewing the financial and other information provided to the Trust by Chesapeake, 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 quarter ended June 30, 2013, 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.

PART II. OTHER INFORMATION

ITEM 1A. Risk Factors

Risk factors relating to the Trust are contained in Part 1, Item 1A of the 2012 Form 10-K. There have not been any material changes from the risk factors previously disclosed in the 2012 Form 10-K.

ITEM 6. Exhibits

The following exhibits are filed or furnished as a part of this report:

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

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: August 8, 2013

CHESAPEAKE GRANITE WASH TRUST

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

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

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

EXHIBIT INDEX

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