CHESAPEAKE ENERGY CORP
Form S-1/A
November 09, 2011

Table of Contents

Index to Financial Statements

As filed with the Securities and Exchange Commission on November 8, 2011

Registration No. 333-175395

UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

REGISTRATION STATEMENT

UNDER

THE SECURITIES ACT OF 1933

Amendment No. 6	**Amendment No. 6**
to	**to**
FORM S-1	**FORM S-3**
Chesapeake Granite Wash Trust	**Chesapeake Energy Corporation**
(Exact name of co-registrant as specified in its charter)	***(Exact name of co-registrant as specified in its charter)***
Delaware	**Oklahoma**
(State or other jurisdiction of incorporation or organization)	***(State or other jurisdiction of incorporation or organization)***
1311	**1311**
(Primary Standard Industrial Classification Code Number)	***(Primary Standard Industrial Classification Code Number)***
45-6355635	**73-1395733**
(I.R.S. Employer Identification No.)	***(I.R.S. Employer Identification No.)***
919 Congress Avenue, Suite 500	**6100 North Western Avenue**
Austin, Texas 78701	**Oklahoma City, Oklahoma 73118**

(512) 236-6599
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)
The Bank of New York Mellon Trust Company, N.A.
919 Congress Avenue, Suite 500
Austin, Texas 78701
(512) 236-6599
Attention: Michael J. Ulrich
(Name, address, including zip code, and telephone number, including area code, of agent for service)

(405) 848-8000
(Address, including zip code, and telephone number, including area code, of registrant s principal executive offices)
Jennifer M. Grigsby
Senior Vice President, Treasurer
and Corporate Secretary
6100 North Western Avenue
Oklahoma City, Oklahoma 73118
(405) 848-8000
(Name, address, including zip code, and telephone number, including area code, of agent for service)

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Approximate date of commencement of proposed sale to the public: As soon as practicable after this Registration Statement becomes effective.

If any of the securities being registered on this Form are to be offered on a delayed or continuous basis pursuant to Rule 415 under the Securities Act of 1933, check the following box: ¨

If this Form is filed to register additional securities for an offering pursuant to Rule 462(b) under the Securities Act, please check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(c) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

If this Form is a post-effective amendment filed pursuant to Rule 462(d) under the Securities Act, check the following box and list the Securities Act registration statement number of the earlier effective registration statement for the same offering. ¨

Indicate by check mark whether the registrant is a large accelerated filer, an accelerated filer, a non-accelerated filer, or a smaller reporting company. See the definitions of large accelerated filer, accelerated filer and smaller reporting company in Rule 12b-2 of the Exchange Act. (Check one):

Chesapeake Granite Wash Trust

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

Chesapeake Energy Corporation

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

The Registrants hereby amend this Registration Statement on such date or dates as may be necessary to delay its effective date until the Registrants shall file a further amendment which specifically states that this Registration Statement shall thereafter become effective in accordance with Section 8(a) of the Securities Act, or until this Registration Statement shall become effective on such date as the Securities and Exchange Commission, acting pursuant to said Section 8(a), may determine.

[Table of Contents](#)

[Index to Financial Statements](#)

EXPLANATORY NOTE

This Amendment No. 6 to the Registration Statement on Forms S-1 and S-3 (Registration Nos. 333-175395 and 333-175395-01) of Chesapeake Granite Wash Trust and Chesapeake Energy Corporation (Chesapeake) is being filed to amend the section of the prospectus entitled Where You Can Find More Information to clarify that filings made by Chesapeake with the U.S. Securities and Exchange Commission pursuant to Sections 13(a), 13(c), 14 and 15(d) of the Securities Exchange Act of 1934, as amended, that are incorporated by reference in the prospectus include those made after the date of the initial registration statement and prior to the effectiveness of the registration statement.

Table of Contents

Index to Financial Statements

The information in this prospectus is not complete and may be changed. We may not sell these securities until the registration statement filed with the Securities and Exchange Commission is effective. This prospectus is not an offer to sell these securities, and we are not soliciting an offer to buy these securities, in any state where the offer or sale is not permitted.

PROSPECTUS (Subject to Completion)

Issued November 8, 2011

23,375,000 Common Units

Chesapeake Granite Wash Trust

REPRESENTING BENEFICIAL INTERESTS

This is an initial public offering of common units representing beneficial interests in Chesapeake Granite Wash Trust. The trust is selling all of the common units offered hereby. Chesapeake Energy Corporation (Chesapeake) will convey to the trust certain royalty interests in exchange for common and subordinated units collectively representing a 50% beneficial interest in the trust (without giving effect to the exercise of the underwriters option to purchase additional units), as well as all of the net proceeds of this offering.

Prior to this offering, there has been no public market for the common units. Chesapeake anticipates that the initial public offering price will be between $19.00 and $21.00 per common unit. The common units have been approved for listing on the New York Stock Exchange under the symbol CHKR.

***The Trust Units.** Trust units, consisting of common and subordinated units, are units representing undivided beneficial interests in the property of the trust. They do not represent any interest in Chesapeake.*

***The Trust.** The trust will own term and perpetual royalty interests in oil, natural gas liquids and natural gas properties leased by Chesapeake in the Colony Granite Wash play, located in Washita County, Oklahoma. These royalty interests will entitle the trust to receive, after the deduction of post-production expenses and taxes, (a) 90% of the proceeds attributable to Chesapeake s net revenue interest in the sale of production from 69 horizontal producing wells and (b) 50% of the proceeds attributable to Chesapeake s net revenue interest in the sale of production from 118 horizontal development wells to be drilled within an Area of Mutual Interest consisting of approximately 45,400 gross acres (28,700 net acres) held by Chesapeake. The number of wells required to be drilled may increase or decrease in proportion to Chesapeake s actual net revenue interest in each well and other factors described herein. The trust will not be responsible for any costs related to the drilling of these wells. The trust will be treated as a partnership for U.S. federal income tax purposes.*

***The Trust Unitholders.** As a trust unitholder, you will receive quarterly distributions of cash from the proceeds that the trust receives from Chesapeake s sale of oil, natural gas liquids and natural gas from properties subject to the royalty interests to be held by the trust. The amount of the distributions will be impacted by oil and natural gas liquids hedges to which the trust will be a party. For information on target distributions and related matters pertinent to trust unitholders, including Chesapeake s right to receive incentive distributions and ownership of subordinated units, please see Target Distributions and Subordination and Incentive Thresholds beginning on page 50.*

Investing in the common units involves a high degree of risk. See Risk Factors beginning on page 20.

These risks include the following:

- *Drilling for and producing oil, natural gas liquids and natural gas involves many risks that could delay the anticipated drilling schedule for the development wells and adversely affect future production, which could decrease cash distributions to unitholders.*
- *Price fluctuations for oil, natural gas liquids and natural gas could reduce proceeds to the trust and decrease cash distributions to unitholders.*

Actual reserves and future production may be less than current estimates.

Estimates of target distributions to unitholders are based on assumptions that are inherently subjective and are subject to significant risks and uncertainties that could cause actual distributions to differ materially from estimates.

Hedging arrangements will cover only a portion of the expected production attributable to the trust, and such arrangements will limit the trust s ability to benefit from commodity price increases for hedged volumes above the corresponding hedge price.

If the trust were treated as a corporation for U.S. federal income tax purposes, then its cash available for distribution to unitholders would be substantially reduced.

If the IRS contests the tax positions the trust takes, the value of the trust units may be adversely affected, the cost of any IRS contest will reduce the trust s cash available for distribution and income, gain, loss and deduction may be reallocated among trust unitholders.

The tax treatment of an investment in trust units could be affected by potential legislative changes, possibly on a retroactive basis.

PRICE $ A COMMON UNIT

	Price to Public	Underwriting Discounts and Commissions[1]	Proceeds to Trust[2]
Per Common Unit	$	$	$
Total	$	$	$

[1] *Excludes an aggregate structuring fee equal to 0.50% of the gross proceeds of this offering, or approximately $ million, payable to Morgan Stanley & Co. LLC and Raymond James & Associates, Inc.*

[2] *The trust will deliver all of the proceeds it receives in this offering to a wholly owned subsidiary of Chesapeake.*

The trust has granted the underwriters an option to purchase up to an additional 3,506,250 common units.

Neither the Securities and Exchange Commission nor any state securities commission has approved or disapproved of these securities or determined if this prospectus is truthful or complete. Any representation to the contrary is a criminal offense.

The underwriters expect to deliver the common units to purchasers on , 2011.

MORGAN STANLEY *RAYMOND JAMES*

Deutsche Bank Securities *Goldman, Sachs & Co.* *Wells Fargo Securities*

, 2011

Table of Contents

Index to Financial Statements

Table of Contents

Index to Financial Statements

TABLE OF CONTENTS

IMPORTANT NOTICE ABOUT INFORMATION IN THIS PROSPECTUS

You should rely only on the information contained in this prospectus or in any free writing prospectus the trust may authorize to be delivered to you. Until , 2011 (25 days after the date of this prospectus), federal securities laws may require all dealers that effect transactions in the common units, whether or not participating in this offering, to deliver a prospectus. This is in addition to the dealers obligation to deliver a prospectus when acting as underwriters and with respect to their unsold allotments or subscriptions.

The trust and Chesapeake have not, and the underwriters have not, authorized anyone to provide you with additional or different information. If anyone provides you with additional, different or inconsistent information, you should not rely on it. This prospectus is not an offer to sell or a solicitation of an offer to buy the common units in any jurisdiction where such offer and sale would be unlawful. You should not assume that the information contained in this prospectus is accurate as of any date other than the date on the front of this document unless otherwise specified herein. The trust s and Chesapeake s business, financial condition, results of operations and prospects may have changed since such date.

Table of Contents

Index to Financial Statements

SUMMARY

This summary provides a brief overview of information contained elsewhere in this prospectus. To understand this offering fully, you should read the entire prospectus carefully, including the risk factors, the summary reserve reports and the financial statements and notes to those statements. Definitions for certain terms relating to the oil and natural gas business can be found in Glossary of Certain Oil and Natural Gas Terms and Terms Related to the Trust beginning on page 124. Ryder Scott Company, L.P., referred to in this prospectus as Ryder Scott, an independent engineering firm, provided the estimates of proved oil, natural gas liquids and natural gas reserves as of June 30, 2011 included in this prospectus. These estimates are contained in summaries prepared by Ryder Scott of its reserve reports for (a) the properties held by Chesapeake from which the royalty interests will be conveyed to the trust and (b) the royalty interests to be held by the trust. These reports are included as Annex A to this prospectus and are referred to in this prospectus as the reserve reports. References to Chesapeake in this prospectus are to Chesapeake Energy Corporation and, where the context requires, its subsidiaries. The royalty interests to be held by the trust are sometimes referred to herein as the trust properties. Unless otherwise indicated, all information in this prospectus assumes an initial public offering price of $20.00 per common unit (the midpoint of the price range set forth on the cover page of this prospectus) and no exercise of the underwriters option to purchase additional common units.

Chesapeake Granite Wash Trust

Chesapeake Granite Wash Trust is a Delaware statutory trust formed in June 2011 to own (a) royalty interests to be conveyed to the trust by Chesapeake in 69 existing horizontal wells in the Colony Granite Wash play located in Washita County in western Oklahoma (the Producing Wells), and (b) royalty interests in 118 horizontal development wells (calculated as described under The Development Wells beginning on page 4) to be drilled exclusively in the Colony Granite Wash (the Development Wells) on properties within an Area of Mutual Interest (as such area may be extended as described below, the AMI). The AMI is limited to only the Colony Granite Wash formation and is depicted by the area identified in the inside front cover of this prospectus, currently consisting of approximately 45,400 gross acres (28,700 net acres) held by Chesapeake. The Colony Granite Wash is a formation encountered at depths between approximately 11,500 feet and 13,000 feet that lies between the top of the Des Moines formation (or top of Colony Granite Wash A) and the top of the Prue formation (or base of Colony Granite Wash C). Chesapeake intends to drill, or cause to be drilled, the Development Wells from proved undeveloped (PUD) drilling locations in the AMI by June 30, 2015 and is obligated to complete such drilling by June 30, 2016.

The royalty interests will be conveyed from Chesapeake s interest in the Producing Wells and the Development Wells (the Underlying Properties) effective as of July 1, 2011. As of July 1, 2011, 64 of the Producing Wells were producing from the Colony Granite Wash and the remaining five Producing Wells had been drilled and were awaiting completion. As of October 28, 2011, all of the Producing Wells were completed and producing. The royalty interest in the Producing Wells (the PDP Royalty Interest) entitles the trust to receive 90% of the proceeds (exclusive of any production or development costs but after deducting post-production expenses and any applicable taxes) from the sale of production of oil, natural gas liquids and natural gas attributable to Chesapeake s net revenue interest in the Producing Wells. The royalty interest in the Development Wells (the Development Royalty Interest) entitles the trust to receive 50% of the proceeds (exclusive of any production or development costs but after deducting post-production expenses and any applicable taxes) from the sale of oil, natural gas liquids and natural gas production attributable to Chesapeake s net revenue interest in the Development Wells.

As of June 30, 2011 and after giving effect to the conveyance of the PDP Royalty Interest and the Development Royalty Interest to the trust, the total reserves estimated to be attributable to the trust were 44.3 mmboe (47.0% oil and natural gas liquids by volume). This amount includes 18.6 mmboe attributable to the PDP Royalty Interest and 25.7 mmboe attributable to the Development Royalty Interest.

1

Table of Contents

Index to Financial Statements

Generally, the percentage of production proceeds to be received by the trust with respect to a well will equal the product of (a) the percentage of proceeds to which the trust is entitled under the terms of the conveyances (90% for the Producing Wells and 50% for the Development Wells) multiplied by (b) Chesapeake s net revenue interest in the well. Chesapeake currently owns on average a 52.8% net revenue interest in the Producing Wells. Therefore, the trust will initially receive an average 47.5% net revenue interest in the Producing Wells. Chesapeake on average owns a 52.0% net revenue interest in the properties on which it expects to drill the Development Wells, and based on this net revenue interest, the trust would have an average 26.0% net revenue interest in the Development Wells. Chesapeake s actual net revenue interest in any particular Producing Well or Development Well may differ from these averages.

Chesapeake will retain 10% of the proceeds from the sale of oil, natural gas liquids and natural gas attributable to its net revenue interest in the Producing Wells, and 50% of the proceeds from the sale of future production attributable to its net revenue interest in the Development Wells. Chesapeake initially will own 50% of the trust units (without giving effect to the exercise of the underwriters option to purchase additional common units). By virtue of Chesapeake s retained interest in the Producing Wells and the Development Wells, as well as its ownership of 50% of the trust units, it would have an effective average net revenue interest of 29.0% in the Producing Wells and 39.0% in the Development Wells, compared with an effective average net revenue interest for the holders of trust units other than Chesapeake of 23.8% in the Producing Wells and 13.0% in the Development Wells.

The trust will not be responsible for any costs related to the drilling of the Development Wells or any other operating and capital costs. The trust s cash receipts in respect of the trust properties will be determined after deducting post-production expenses and any applicable taxes associated with the PDP Royalty Interest and the Development Royalty Interest. These post-production expenses will generally consist of costs incurred to gather, store, compress, transport, process, treat, dehydrate and market the oil, natural gas liquids and natural gas produced. However, the trust will not be responsible for costs of marketing services provided by Chesapeake. Cash distributions to unitholders will be increased or decreased by the effect of the trust s hedging arrangements related to oil and natural gas liquids production and reduced by trust expenses.

The trust will be a party to hedging arrangements covering a portion of its oil and natural gas liquids production through September 30, 2015. As a party to these contracts, the trust will receive payments directly from its counterparties and be required to pay any amounts owed directly to its counterparties. The trust will hedge approximately 50% of the expected oil and natural gas liquids production and 37% of the trust s expected revenues (based on NYMEX strip oil prices as of October 28, 2011) upon which the target distributions from October 1, 2011 through September 30, 2015 are based. Following this offering, except in limited circumstances involving the restructuring of an existing hedge, the trust will have no ability to terminate its hedging arrangements or enter into additional hedges. Except in connection with the restructuring of an existing hedge, no production after September 30, 2015 will be hedged. The trust s royalty interests in the Underlying Properties will be pledged to the hedge counterparties to provide credit support for the hedge transactions, and the hedging counterparties may foreclose on such lien if, among other things, the trust or Chesapeake is in material default of the drilling, payment or reporting requirements under the hedging arrangements, subject to applicable cure and notice periods. Please see The Trust Hedging Arrangements beginning on page 48 and Target Distributions and Subordination and Incentive Thresholds beginning on page 52.

The trust will make quarterly cash distributions of substantially all of its cash receipts, after deducting the trust s expenses, approximately 60 days following the completion of each quarter through (and including) the quarter ending June 30, 2031, except that the first distribution, which will cover the third quarter of 2011 (consisting of proceeds

Table of Contents

Index to Financial Statements

attributable to July and August 2011 production), is expected to be made on or about December 28, 2011 to record unitholders on or about December 15, 2011. The Bank of New York Mellon Trust Company, N.A., as trustee, intends to withhold $1.0 million from the first distribution to establish an initial cash reserve available for trust expenses.

The PDP Royalty Interest and the Development Royalty Interest will each consist of two separate royalty interests conveyed by Chesapeake to the trust: (a) a term royalty interest for a period of 20 years commencing on July 1, 2011 and ending on June 30, 2031 (such date is referred to as the Termination Date and such interests are referred to as the Term Royalties) and (b) a perpetual royalty interest that does not terminate (together, the Perpetual Royalties). The trust will dissolve and begin to liquidate on the Termination Date and will soon thereafter wind up its affairs and terminate. At the Termination Date, the Term Royalties will revert automatically to Chesapeake. Following the Termination Date, the Perpetual Royalties will be sold by the trust, and the net proceeds of the sale, as well as any remaining trust cash reserves, will be distributed to the unitholders pro rata. Chesapeake will have a right of first refusal to purchase the Perpetual Royalties from the trust following the Termination Date.

Chesapeake currently operates 94% of the Producing Wells and expects to operate approximately 93% of the Development Wells until the completion of its drilling obligation. Chesapeake will market, or cause to be marketed, the oil, natural gas liquids and natural gas produced from the Underlying Properties. The conveyance instruments obligate Chesapeake to conduct operations and market production in good faith and in accordance with the Reasonably Prudent Operator Standard described under The Development Wells below.

Prior to fulfilling its drilling obligation to the trust, Chesapeake may cause the trust to exchange leased acreage in the AMI for other leased acreage in the sections adjacent to the AMI (such adjacent sections are referred to as the Development Area). If additional acreage in the Development Area becomes subject to the royalty interests, then the AMI will automatically expand to include such acreage. In addition, if Chesapeake acquires any additional leases or interests in the AMI, Chesapeake may make such additional leases or interests subject to the royalty interests of the trust with respect to any Development Wells subsequently drilled on such acreage. However, the aggregate acreage attributable to the exchanged leases or additional leases or acreage may not exceed five percent of the acreage initially subject to the royalty interests and the reserve profile of the newly burdened acreage must be consistent with the reserve profile of the acreage released by the trust. See Description of the Royalty Interests Additional Features of the Royalty Interests Exchange and Addition of Acreage on page 84.

Following the satisfaction of its drilling obligation to the trust, Chesapeake may, without the consent or approval of the trust unitholders, sell all or any part of its retained interest in the Underlying Properties. In any such sale by Chesapeake, the Underlying Properties must be sold subject to and burdened by the trust s royalty interests, except that Chesapeake may require the trust to release the trust s royalty interests on such Underlying Properties with an aggregate value of up to $5.0 million during any 12-month period. In such event, the trust must receive an amount equal to the fair value to the trust of any royalty interests it sells. See Description of the Royalty Interests Additional Features of the Royalty Interests Sale and Release of Underlying Properties on page 84.

The business and affairs of the trust will be managed by the trustee. The trustee will have no ability to manage or influence the operation of the Underlying Properties. Chesapeake will have no ability to manage or influence the management of the trust except through its limited voting rights as a holder of trust units. Please see Description of the Trust Units Voting Rights of Trust Unitholders beginning on page 93.

The principal offices of the trust are located at 919 Congress Avenue, Suite 500, Austin, Texas 78701, and its telephone number is (512) 236-6599.

3

Table of Contents

Index to Financial Statements

The Development Wells

Pursuant to a development agreement with the trust, Chesapeake intends to drill, or cause to be drilled, 118 Development Wells in the AMI by June 30, 2015 and is obligated to complete such drilling by June 30, 2016. 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 will receive proportionate credit. As a result, Chesapeake may be required to drill more or less than 118 wells in order to fulfill its drilling obligation. See The Trust Development Agreement and Drilling Support Lien beginning on page 46. Since July 1, 2011, Chesapeake has drilled and completed seven Development Wells and has drilled two additional wells in the AMI that are awaiting completion as of the date of this prospectus. Assuming the successful completion of these two wells, such wells will count toward the satisfaction of Chesapeake s drilling obligation.

Until Chesapeake has satisfied its drilling obligation, it will not be permitted to drill or complete any well on lease acreage included within the AMI for its own account. For the life of the trust, Chesapeake will not be permitted to drill or complete any well that will have a perforated segment within 600 feet of any perforated interval of any Development Well or Producing Well.

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. We refer to this standard as the Reasonably Prudent Operator Standard. Where Chesapeake does not operate the Underlying Properties, Chesapeake is required to use commercially reasonable efforts to exercise its contractual rights to cause the operators of such Underlying Properties to adhere to the Reasonably Prudent Operator Standard. Chesapeake expects that the drilling and completion techniques used for the Development Wells will be generally consistent with those used for the Producing Wells and other Colony Granite Wash producing wells outside of the AMI. The proved undeveloped reserves reflected in the reserve reports assume that Chesapeake will drill and complete the 118 Development Wells with the same completion technique as the 69 Producing Wells.

Chesapeake will grant to the trust a lien on its interest in the AMI (except the Producing Wells and any other wells that are already producing and not subject to the royalty interests) in order to secure the estimated amount of the drilling costs for the trust s interests in the Development Wells (the Drilling Support Lien). The amount obtained by the trust pursuant to the Drilling Support Lien initially may not exceed $262.7 million. As Chesapeake fulfills its drilling obligation over time, Development Wells that are completed or that are perforated for completion and then plugged and abandoned will be 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 will be proportionately reduced.

As of the date of this prospectus, Chesapeake s drilling activity with respect to the Development Wells is consistent with the drilling schedule contemplated by the development agreement. The drilling schedule provides that approximately 30 wells are expected to be drilled each year until the drilling obligation is fulfilled.

Underlying Properties

The Underlying Properties are located in the Colony Granite Wash play in Washita County in western Oklahoma. The Colony Granite Wash is a subset of the greater Granite Wash plays of the Anadarko Basin. The Colony Granite Wash is situated at the eastern end of a series of Des

Moines-age granite wash fields that extend along the southern flank of the Anadarko basin, approximately 60 miles into the Texas Panhandle. These granite wash fields were generally deposited as deep-water turbidites that result in relatively low risk, laterally extensive reservoirs. The productive members of the Colony Granite Wash are encountered between

Table of Contents

Index to Financial Statements

approximately 11,500 and 13,000 feet and lie stratigraphically between the top of the Des Moines formation (or top of Colony Granite Wash A) and the top of the Prue formation (or base of Colony Granite Wash C). The individual productive members within the Colony Granite Wash may reach 200 feet or more in gross interval thickness and the targeted porosity zones within these individual members are generally 20 to 75 feet thick. The Colony Granite Wash is primarily a natural gas and natural gas condensate reservoir based on reserve volumes. However, oil and natural gas liquids production generates more revenue than natural gas production in the Colony Granite Wash due to prices that have historically been, and currently are, significantly higher for oil and natural gas liquids than for natural gas. Development costs for horizontal wells drilled and completed in the AMI average approximately $8.31 per boe, which is comparable to the development costs in other large-scale resource developments in the Mid-Continent in which Chesapeake operates.

Chesapeake began drilling horizontal wells in the Colony Granite Wash in 2007. Chesapeake is the largest leaseholder in the Colony Granite Wash, with approximately 61,100 net acres (of which 28,700 net acres will be subject to the trust s royalty interests), the most active driller in the play, based on rig count, and the largest producer in the play. Since 2007, there have been 173 Des Moines horizontal wells drilled in the Colony Granite Wash. Of those 173 wells, Chesapeake has drilled 133 wells and participated in another 35 wells. As of June 30, 2011, there were 15 rigs drilling horizontal wells in the formation, with nine of those rigs drilling for Chesapeake. While horizontal wells are more expensive than vertical wells, a horizontal well increases the production of hydrocarbons and adds significant recoverable reserves per well. In addition, an operator can achieve better returns on drilling investments with horizontal drilling because the production from one horizontal well is equal to the production from several vertical wells. While Chesapeake is the most active company in this play, other operators in the Colony Granite Wash include publicly-listed companies such as Penn Virginia Corporation, Apache Corporation, QEP Resources, Inc., SM Energy Company and Marathon Oil Corporation, and privately-held companies such as Samson Oil & Gas Limited, Chaparral Energy, Inc. and Ward Petroleum Corporation.

Target Distributions and Subordination and Incentive Thresholds

Chesapeake has established quarterly target levels of cash distributions to unitholders for the life of the trust as set forth in Annex B to this prospectus. Actual cash distributions to the trust unitholders will fluctuate quarterly based on the quantity of oil, natural gas liquids and natural gas produced from the Underlying Properties, the prices received for such production, when Chesapeake receives payment for such production, payments under the hedge arrangements, the trust s expenses and other factors. As shown in Annex B, while target distributions initially increase as Chesapeake completes its drilling obligation and production increases, over time target distributions decline as a result of the depletion of the reserves in the Underlying Properties. While these target distributions do not represent the actual distributions you will receive with respect to your common units, they were used to calculate the subordination and incentive thresholds described in more detail below. The target distributions were derived by assuming that oil, natural gas liquids and natural gas production from the trust properties will equal the volumes reflected in the reserve reports included as Annex A to this prospectus and that prices received for such production will be consistent with spot and settled NYMEX pricing for July through November 2011, monthly NYMEX forward pricing as of October 28, 2011 for the remainder of the period ending June 30, 2014 and assumed price increases after June 30, 2014 of 2.5% annually, capped at $120.00 per bbl of oil and $7.00 per mmbtu of natural gas. Using these assumptions, the price of oil would reach the $120.00 per bbl cap in 2025 and the price of natural gas would reach the $7.00 per mmbtu cap in 2028. The target distributions also give effect to estimated post-production expenses, projected trust administrative expenses and actual production for July and August of 2011.

In order to provide support for cash distributions on the common units, Chesapeake has agreed to subordinate 11,687,500 of the trust units it will retain following this offering, which will constitute 25% of the outstanding trust units. The subordinated units will be 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

5

Table of Contents

Index to Financial Statements

than the applicable quarterly subordination threshold. If there is not sufficient cash to fund such a distribution on all of the common units, the distribution to be made with respect to the subordinated units will be reduced or eliminated for such quarter in order to make a distribution, to the extent possible, of up to the subordination threshold amount on all the common units, including the common units held by Chesapeake. Each quarterly subordination threshold is 20% below the target distribution level for the corresponding quarter (each, a subordination 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 will be entitled to receive incentive distributions equal to 50% of the amount by which the cash available for distribution on all of the trust units in any quarter is 20% greater than the target distribution for such quarter (each, an incentive threshold). The remaining 50% of cash available for distribution in excess of the incentive thresholds will be paid to trust unitholders, including Chesapeake, on a pro rata basis.

By way of example, if the target distribution per unit for a particular quarterly period is $0.54, then the subordination threshold would be $0.43 and the incentive threshold would be $0.65 for such quarter. This means that if the cash available for distribution to all holders for that quarter would result in a per unit distribution below $0.43, the distribution to be made with respect to subordinated units will be reduced or eliminated in order to make a distribution, to the extent possible, up to the amount of the subordination threshold, on the common units. If, on the other hand, the cash available for distribution to all holders would result in a per unit distribution above $0.65, then Chesapeake would receive 50% of the amount by which the cash available for distribution on all the trust units exceeds $0.65, with all trust unitholders (including Chesapeake on a pro rata basis) sharing in the other 50% of such excess amount. See Target Distributions and Subordination and Incentive Thresholds beginning on page 52.

At the end of the fourth full calendar quarter following Chesapeake s satisfaction of its drilling obligation with respect to the Development Wells, the subordinated units will automatically convert into common units on a one-for-one basis and Chesapeake s right to receive incentive distributions will terminate. After such time, the common units will no longer have the protection of the subordination threshold, and all trust unitholders will share on a pro rata basis in the trust s distributions. Chesapeake currently intends to complete its drilling obligation on or before June 30, 2015 and accordingly, Chesapeake expects the subordinated units will convert into common units on or before June 30, 2016. Chesapeake is obligated to complete its drilling obligation by June 30, 2016, in which event the subordinated units would convert into common units on or before June 30, 2017. The period during which the subordinated units are outstanding is referred to as the subordination period.

Chesapeake s management has prepared the prospective financial information set forth below to present the target cash distributions to the holders of the trust units based on the estimates and assumptions described under Target Distributions and Subordination and Incentive Thresholds beginning on page 52. The accompanying prospective financial information was not prepared with a view toward complying with the regulations of the U.S. Securities and Exchange Commission (the SEC) or the guidelines established by the American Institute of Certified Public Accountants with respect to preparation and presentation of prospective financial information. More specifically, such information omits items that are not relevant to the trust. Chesapeake s management believes the prospective financial information was prepared on a reasonable basis, reflects the best currently available estimates and judgments, and presents, to the best of management s knowledge and belief, the expected course of action and the expected future financial performance of the royalty interests. However, this information is based on estimates and judgments, and readers of this prospectus are cautioned not to place undue reliance on the prospective production or financial information.

Table of Contents

Index to Financial Statements

The prospective financial information included in this prospectus has been prepared by, and is the responsibility of, Chesapeake s management. PricewaterhouseCoopers LLP, the trust s and Chesapeake s independent registered public accountant, has neither examined, compiled nor performed any procedures with respect to the accompanying prospective financial information and, accordingly, PricewaterhouseCoopers LLP does not express an opinion or any other form of assurance with respect thereto. The reports of PricewaterhouseCoopers LLP included or incorporated by reference in this prospectus relate to the Statement of Assets and Trust Corpus of the trust, the historical Statements of Revenues and Direct Operating Expenses of the Underlying Properties and the historical financial statements of Chesapeake. The reports do not extend to the prospective financial information and should not be read to do so.

The following table sets forth the target distributions and subordination and incentive thresholds for each calendar quarter through the second quarter of 2017 (the last quarter for which subordinated units would be outstanding if Chesapeake does not complete its drilling obligation on or before June 30, 2016). The effective date of the conveyance of the royalty interests is July 1, 2011, which means that the trust will be credited with the proceeds of production attributable to the royalty interests from that date even though the trust properties will not be conveyed to the trust until the closing of this offering. Please see Calculation of Target Distributions below. The first distribution, which will cover the third quarter of 2011, is expected to be made on or about December 28, 2011 to record unitholders on or about December 15, 2011. Due to the timing of the payment of production proceeds to the trust, the trust expects that the first distribution will include royalties attributable to sales of oil, natural gas liquids and natural gas for two months (July and August 2011). Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, including the first two months of the quarter just ended and the last month of the quarter prior to that one. The trustee intends to withhold $1.0 million from the first distribution to establish an initial cash reserve available for trust expenses.

7

Table of Contents

Index to Financial Statements

Period	Subordination Threshold[1]	Target Distribution (per unit)	Incentive Threshold[1]
2011:			
Third Quarter[2]	$ 0.43	$ 0.54	$ 0.65
Fourth Quarter	0.54	0.68	0.82
2012:			
First Quarter	0.59	0.74	0.89
Second Quarter	0.61	0.76	0.91
Third Quarter	0.63	0.79	0.94
Fourth Quarter	0.67	0.84	1.01
2013:			
First Quarter	0.69	0.87	1.04
Second Quarter	0.69	0.86	1.04
Third Quarter	0.71	0.89	1.07
Fourth Quarter	0.69	0.86	1.04
2014:			
First Quarter	0.69	0.87	1.04
Second Quarter	0.68	0.85	1.02
Third Quarter	0.69	0.86	1.03
Fourth Quarter	0.66	0.83	0.99
2015:			
First Quarter	0.66	0.83	0.99
Second Quarter	0.68	0.85	1.02
Third Quarter	0.64	0.80	0.96
Fourth Quarter	0.56	0.70	0.84
2016			
First Quarter	0.51	0.63	0.76
Second Quarter	0.47	0.58	0.70
Third Quarter	0.44	0.55	0.66
Fourth Quarter	0.41	0.52	0.62
2017			
First Quarter	0.39	0.49	0.59
Second Quarter	0.37	0.47	0.56

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

(2) Includes proceeds attributable to two months of actual production from July 1, 2011 to August 31, 2011, and gives effect to the establishment of $1.0 million of reserves for expenses withheld by the trustee.

For additional information with respect to the subordination and incentive thresholds, please see Target Distributions and Subordination and Incentive Thresholds beginning on page 52.

Table of Contents

Index to Financial Statements

Calculation of Target Distributions

The following table presents the calculation of the target distributions for each quarter through and including the quarter ending June 30, 2012. The target distributions were prepared by Chesapeake based on assumptions of production volumes, pricing and other factors. The production forecasts used to calculate target distributions are based on estimates by Ryder Scott contained in the reserve reports. Payments to unitholders will be made approximately 60 days following the end of each calendar quarter, except that the first distribution is expected to be made on or about December 28, 2011 to record unitholders on or about December 15, 2011. Please read Target Distributions and Subordination and Incentive Thresholds Significant Assumptions Used to Calculate the Target Distributions beginning on page 58.

	Three Months Ending			
Period	**September 30, 2011[1][2]**	**December 31, 2011[1]**	**March 31, 2012[1]**	**June 30, 2012[1]**
	(In thousands, except volumetric and per unit data)			
Estimated production from trust properties				
Oil sales volumes (mbbls)	133	176	181	181
Natural gas liquids sales volumes (mbbls)	218	298	302	304
Natural gas sales volumes (mmcf)	2,153	2,867	2,909	2,923
Total sales volumes (mboe)	710	952	967	972
% PDP sales volumes	98%	84%	69%	61%
% PUD sales volumes	2%	16%	31%	39%
% Oil volumes	19%	19%	19%	19%
% Natural gas liquids volumes	31%	31%	31%	31%
% Natural gas volumes	50%	50%	50%	50%
Commodity price and derivative contract positions				
NYMEX price[3]				
Oil ($/bbl)	$ 91.52	$ 85.43	$ 93.20	$ 93.00
Natural gas liquids ($/bbl)	$ 45.06	$ 42.03	$ 45.85	$ 45.75
Natural gas ($/mmbtu)	$ 4.36	$ 3.71	$ 4.00	$ 4.02
Assumed realized weighted unhedged price[4]				
Oil ($/bbl)	$ 87.94	$ 81.85	$ 89.62	$ 89.41
Natural gas liquids ($/bbl)	$ 42.66	$ 39.73	$ 43.47	$ 43.23
Natural gas ($/mcf)	$ 3.12	$ 2.42	$ 2.76	$ 2.93
Assumed realized weighted hedged price[5]				
Oil ($/bbl)	$ 87.94	$ 81.21	$ 85.37	$ 85.66
Natural gas liquids ($/bbl)	$ 42.66	$ 39.41	$ 41.38	$ 41.38
Percent of oil volumes hedged		33.4%	49.9%	50.0%
Oil hedged price ($/bbl)	$	$ 84.18	$ 84.74	$ 85.48
Percent of natural gas liquids volumes hedged		33.6%	50.0%	50.0%
Natural gas liquids hedged price ($/bbl)	$	$ 41.41	$ 41.68	$ 42.05
Estimated cash available for distribution				
Oil sales revenues	$ 11,736	$ 14,422	$ 16,184	$ 16,198
Natural gas liquids sales revenues	9,285	11,838	13,126	13,121
Natural gas sales revenues	6,707	6,945	8,038	8,578
Realized gains (losses) from derivative contracts		(207)	(1,398)	(1,241)
Operating revenues and realized gains (losses) from derivative contracts	27,729	32,998	35,951	36,656

Production taxes	(1,023)	(924)	(987)	(974)
Trust administrative expenses(6)	(1,327)	(250)	(250)	(250)
Total trust expenses	(2,350)	(1,174)	(1,237)	(1,224)
Cash available for distribution	$ 25,379	$ 31,825	$ 34,714	$ 35,432
Trust units outstanding	46,750	46,750	46,750	46,750
Target distribution per trust unit	$ 0.54	$ 0.68	$ 0.74	$ 0.76
Subordination threshold per trust unit	$ 0.43	$ 0.54	$ 0.59	$ 0.61
Incentive threshold per trust unit	$ 0.65	$ 0.82	$ 0.89	$ 0.91

Table of Contents

Index to Financial Statements

(1) The three months ending September 30, 2011 include proceeds attributable to two months of production from July 1, 2011 to August 31, 2011. Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, including the first two months of the quarter just ended as well as the last month of the quarter prior to that one.

(2) The three months ending September 30, 2011 reflect historical production volumes for July and August 2011 and management estimates of production taxes for July and August 2011.

(3) Average NYMEX spot, settled and futures prices, as reported October 28, 2011. For a description of the effect of lower NYMEX prices on target cash distributions, please read Target Distributions and Subordination and Incentive Thresholds Sensitivity of Target Distributions to Changes in Oil, Natural Gas Liquids and Natural Gas Prices and Volumes beginning on page 63.

(4) Sales price net of forecasted gravity quality, btu content, transportation costs, and marketing costs. For information about the estimates and assumptions made in preparing the table above, see Target Distributions and Subordination and Incentive Thresholds Significant Assumptions Used to Calculate the Target Distributions beginning on page 58.

(5) No hedging arrangements will cover natural gas.

(6) Includes the establishment of an initial cash reserve of $1.0 million for trust expenses in period ending September 30, 2011.

Chesapeake Energy Corporation

Chesapeake is the second-largest producer of natural gas, is among the top 15 producers of oil and natural gas liquids and is the most active driller, based on rig count, of new oil and natural gas wells in the U.S. Chesapeake s operations are focused on discovering and developing unconventional natural gas and oil fields onshore in the U.S. Chesapeake owns leading positions in the Barnett, Haynesville, Bossier, Marcellus and Pearsall natural gas shale plays and in the Granite Wash, Cleveland, Tonkawa, Mississippian, Bone Spring, Avalon, Wolfcamp, Wolfberry, Eagle Ford, Niobrara, Frontier, Codell, Bakken/Three Forks and Utica unconventional liquids plays. It has also vertically integrated its operations and owns substantial midstream, compression, drilling and oilfield service assets. As of June 30, 2011, Chesapeake had total assets of approximately $36.7 billion and total estimated net proved reserves of 16.5 tcfe. Chesapeake has approximately 61,100 net acres leased in the Colony Granite Wash and as of June 30, 2011, Chesapeake was operating nine rigs in the Colony Granite Wash.

Chesapeake s principal executive offices are located at 6100 North Western Avenue, Oklahoma City, Oklahoma 73118 and its telephone number is (405) 848-8000. Chesapeake s website is *www.chk.com*; however, the information contained on Chesapeake s website is not incorporated by reference into this prospectus.

The trust units do not represent interests in or obligations of Chesapeake.

Key Investment Considerations

The following are some key investment considerations related to the Underlying Properties, the royalty interests and the common units:

The royalty interests being contributed to the trust are from the highly-productive Colony Granite Wash Play. The existing Producing Wells and the Development Wells to be drilled target the Colony Granite Wash play within the broader Granite Wash formation of the Anadarko Basin, which is the largest non-shale resource play in the Mid-Continent. This highly-productive play has been a focus area for recent development, with 173 horizontal wells targeting the Des Moines formation drilled in the Colony Granite Wash since 2007. Of those 173 wells, Chesapeake has drilled 133 wells and participated in another 35 wells. As of June 30, 2011, there were 15 active rigs drilling horizontal wells in the play, with nine of those rigs drilling for Chesapeake.

Liquids-weighted revenue and production profiles provide long-term exposure to oil prices. Over the 20-year producing life of the trust, 72% of net revenues (based on October 28, 2011 strip prices) and 48% of production are projected to be derived from oil and natural gas liquids. Although natural gas liquids typically sell for less than oil on a volume equivalency basis, natural gas liquids prices have historically been highly correlated with oil prices. As a result, the unhedged portion of liquids revenues during the hedge period and all liquids revenues beyond the hedge period are directly exposed to oil prices, and the amount of trust distributions and consequently trust performance is expected to be highly correlated to fluctuations in the price of oil.

Royalty interests not burdened by operating or capital costs. The trust will not be responsible for any operating or capital costs associated with the Underlying Properties, including the costs to drill and complete the Development Wells. The trust will bear its proportionate share of post-production expenses, any applicable taxes and trust expenses.

Exposure to oil and natural gas liquids price volatility mitigated through September 30, 2015. The trust will be a party to hedging arrangements covering a portion of the trust s expected oil and natural gas liquids production through September 30, 2015. The trust will hedge approximately 50% of the expected oil and natural gas liquids production and approximately 37% of the trust s expected revenues (based on NYMEX strip oil prices as of October 28, 2011) upon which the target distributions from October 1, 2011 through September 30, 2015 are based. These hedging arrangements are expected to reduce the trust s exposure to fluctuations in the prices of oil through the third quarter of 2015.

Alignment of interests between Chesapeake and the trust unitholders. Chesapeake has significant incentives to complete its drilling obligation and increase production from the Underlying Properties as a result of the following factors:

Chesapeake will initially have a significant economic interest in the Underlying Properties through its 50% retained interest in the Development Wells, 10% retained interest in the Producing Wells and its ownership of approximately 50% of the trust units.

A portion of the trust units that Chesapeake will own, constituting 25% of the total outstanding trust units, will be subordinated units that will not be entitled to receive distributions unless there is sufficient cash to pay the subordination threshold amount to the common units. In addition, these subordinated units will only convert into common units at the end of the fourth full calendar quarter following Chesapeake s satisfaction of its drilling obligation to the trust.

To the extent that the trust has cash available for distribution in excess of the incentive thresholds during the subordination period, Chesapeake will be entitled to receive 50% of such cash as incentive distributions, plus its pro rata share of the remaining 50% of such cash by virtue of its ownership of 23,375,000 total units.

Chesapeake will not be permitted to drill or complete any wells for its own account within the AMI or sell the Underlying Properties until it has satisfied its drilling obligation.

If Chesapeake does not fulfill its drilling obligation by June 30, 2016, the trust may foreclose on the Drilling Support Lien on the Underlying Properties. See The Trust Development Agreement and Drilling Support Lien beginning on page 46.

The Colony Granite Wash represents a core asset for Chesapeake. The approximately 61,100 net acres held by Chesapeake in the Colony Granite Wash represent one of its core assets. Chesapeake has grown its position in the Colony Granite Wash since it began drilling horizontal wells there in 2007 based on its belief that the formation can provide attractive returns on invested capital and its belief that the play will further Chesapeake s goal of increasing the proportion of its liquids production. As of June 30, 2011, Chesapeake had nine rigs drilling horizontal wells in the Colony Granite Wash.

Chesapeake is an experienced operator in the Colony Granite Wash. Since 2007, Chesapeake has drilled, as operator, 133 of the 173 horizontal wells drilled by the industry in the Colony Granite Wash to date, 131 of which are completed and the remaining two of which are awaiting completion and expected to be productive. Of the 133 horizontal wells drilled by Chesapeake in the Colony Granite Wash, 125 are located in Washita County, in which the Underlying Properties are located. Chesapeake expects to operate approximately 93% of the Development Wells until the completion of its drilling obligation, allowing Chesapeake to control the timing and amount of discretionary expenditures for operational and development activities with respect to the majority of the Development Wells.

The Colony Granite Wash is serviced by well-developed gathering systems and transportation pipelines. Chesapeake s affiliate, Chesapeake Midstream Partners, L.P. (Chesapeake Midstream Partners), provides Chesapeake with gathering, treating and compression services for natural gas produced in the Colony Granite Wash and is expected to continue to provide these services with respect to substantially all of the natural gas and natural gas liquids produced by the Underlying Properties. The natural gas gathering systems are connected to an extensive intrastate natural gas transportation pipeline system owned by Enogex LLC (Enogex), a subsidiary of publicly-held OGE Energy Corp. Chesapeake s wholly owned subsidiary, Chesapeake Midstream Development, L.P. (Chesapeake Midstream Development), gathers oil production from the Colony Granite Wash through its gathering systems and third parties gather other oil by truck. The oil is further transported to Plains All American Pipeline, L.P. (Plains), a publicly-held master limited partnership, through its pipeline and by truck. The well-developed gathering systems in the Colony Granite Wash and Chesapeake s affiliation with the primary service providers allow close coordination regarding the availability of midstream services and reduce the risk that such services would not be available as Development Wells are drilled.

Rigs and services readily available to allow timely drilling and completion of wells. Chesapeake s substantial oilfield service operations, including drilling rigs, pressure pumping equipment, trucking, oilfield tools, location and road construction and roustabout services, support its drilling activities and will allow Chesapeake to manage the development of the trust s leasehold efficiently and strategically. As of June 30, 2011, Chesapeake had nine drilling rigs operating in the Colony Granite Wash and owned or leased a total of 133 drilling rigs, which it uses to drill wells for its own account. Chesapeake estimates that only four to five rigs will be required to complete its drilling obligation within its contractual commitment to the trust. Chesapeake may use a combination of its own rigs and oilfield service businesses and third party rigs and services to drill and complete the Development Wells. Chesapeake s direct access to drilling rigs and related oilfield services should substantially mitigate any potential shortage of drilling and completion equipment and enable Chesapeake to achieve its projected drilling schedule.

Potential for initial depletion to be offset by results of development drilling. Chesapeake intends to drill, or cause to be drilled, all of the Development Wells on PUD drilling locations in the AMI by June 30, 2015 and is obligated to complete such drilling by June 30, 2016. Furthermore, Chesapeake is incentivized to increase production in the near term due to its substantial ownership of trust units, the subordination and incentive distribution provisions of those units and its retained interest in the Underlying Properties. While production from the trust properties will decline over the long term, the anticipated production from the Development Wells is expected to more than offset depletion of the Producing Wells during the drilling period.

Recognized sponsor with a successful track record and active drilling program. Chesapeake maintains the industry s most active drilling program, based on rig count. In 2010, Chesapeake drilled 1,445 gross (938 net) operated wells and participated in another 1,586 gross (211 net) wells operated by other companies. Chesapeake s drilling success rate in 2010 was 98% for both company-operated and non-operated wells. Daily production for 2010 averaged 2.836 bcfe, an increase of 355 mmcfe, or 14%, over the 2.481 bcfe of daily production for 2009, and consisted of 2.534 bcf of natural gas (89% on a natural gas equivalent basis) and 50,397 bbls of oil and natural gas liquids (11% on a natural gas equivalent basis). 2010 was Chesapeake s 21st consecutive year of production growth.

Table of Contents

Index to Financial Statements

Proved Reserves

Proved Reserves of Underlying Properties and Royalty Interests. The following table sets forth certain estimated proved reserves and the PV-10 value as of June 30, 2011 attributable to the Underlying Properties, the PDP Royalty Interest and the Development Royalty Interest, in each case derived from the reserve reports. The reserve reports were prepared by Ryder Scott in accordance with criteria established by the SEC.

Proved reserve quantities attributable to the royalty interests are calculated by multiplying the gross reserves for each property attributable to Chesapeake s interest by the royalty interest assigned to the trust in each property. The reserves related to the Underlying Properties include all proved reserves expected to be economically produced during the life of the properties. The reserves attributable to the trust s interests include only the reserves attributable to the Underlying Properties that are expected to be produced within the 20-year period prior to the Termination Date as well as the residual 50% interest in the royalty interests that the trust will own on the Termination Date and subsequently sell. A summary of the reserve reports is included as Annex A to this prospectus.

	Proved Reserves[(1)]				
	Oil (mbbl)	Natural Gas Liquids (mbbl)	Natural Gas (mmcf)	Total (mboe)	PV-10 Value[(2)] (In thousands)
Underlying Properties:					
Developed	2,648	7,791	75,689	23,054	343,504
Undeveloped	8,290	18,640	179,931	56,919	510,087
Total	10,938	26,431	255,620	79,973	853,591
Royalty Interests:					
Developed (90%)	2,233	6,235	60,536	18,557	325,434
Undeveloped (50%)	4,002	8,319	80,325	25,709	485,706
Total	6,235	14,554	140,861	44,266	811,140

(1) The proved reserves were determined using a 12-month unweighted arithmetic average of the first-day-of-the-month prices for oil, natural gas liquids and natural gas for the period from July 1, 2010 through June 1, 2011, without giving effect to derivative transactions, and were held constant for the life of the properties. The prices used in the reserve reports, as well as Chesapeake s internal reports, yield weighted average prices at the wellhead, which are based on first-day-of-the-month reference prices and adjusted for transportation and regional price differentials and, for the royalty interests, costs of marketing services provided by Chesapeake affiliates, which will not be charged to the trust. The reference prices and the equivalent weighted average wellhead prices as of June 30, 2011 are presented in the table below.

	Oil (per bbl)	Natural gas liquids (per bbl)	Natural gas (per mcf)
Trailing 12-month average pricing	$ 89.86	$ 89.86	$ 4.21
Weighted average wellhead prices (Underlying Properties)	$ 86.08	$ 39.83	$ 2.93
Weighted average wellhead prices (royalty interests)	$ 86.09	$ 39.80	$ 2.86

(2) PV-10 is the present value of estimated future net revenue to be generated from the production of proved reserves, discounted using an annual discount rate of 10% (as required by the SEC), calculated without deducting future income taxes. PV-10 is a non-GAAP financial measure and

generally differs from standardized measure of discounted net cash flows, or Standardized Measure, the most directly comparable GAAP financial measure, because it does not include the effects of income taxes on future net revenues. Because the historical financial information related to the Underlying Properties consists solely of revenues and direct operating expenses and does not include the effect of income taxes, we expect the PV-10 and Standardized Measure attributable to the Underlying Properties for each period to be the same. Because the trust will not bear federal income tax expense, we also expect the PV-10 and Standardized Measure attributable to the royalty interests for each period to be the same. Neither PV-10 nor Standardized Measure represents an estimate of the fair market value of the Underlying Properties or the royalty interests. We and others in our industry use PV-10 as a measure to compare the relative size and value of proved reserves held by companies without regard to the specific tax characteristics of such entities. PV-10 for the royalty interests has been calculated without deduction for production and development costs, as the trust will not bear those costs.

Table of Contents

Index to Financial Statements

At the Termination Date, the estimated reserves attributable to the residual 50% interest in the royalty interests that the trust will own on the Termination Date and subsequently sell are 5.0 mmboe. The PV-10 value of such reserves calculated using 12-month trailing SEC pricing as of June 30, 2011 is $9.2 million.

Underlying Production Attributable to Target Distributions. The following production bar graph summarizes estimated production underlying trust revenues used to determine Target Distributions.

(1) Due to the July 1, 2011 effective date of the royalty interests and the timing of payments received by the trust for production in determining Target Distributions, the 2011 production forecast includes production from July 1, 2011 through November 30, 2011.

(2) Due to the June 30, 2031 termination date of the trust and the timing of payments received by the trust for production in determining Target Distributions, the 2031 production forecast includes production from December 1, 2030 to June 30, 2031.

(3) Net production for 2011 includes historical production volumes for July and August 2011.

Table of Contents

Index to Financial Statements

Key Risk Factors

Below is a summary of certain key risk factors related to the Underlying Properties, the royalty interests and the common units. This list is not exhaustive. Please also read carefully the full discussion of these risks and other risks described under Risk Factors beginning on page 20.

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

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

- Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the trust and the value of the trust units.

- Estimates of target distributions to unitholders, subordination thresholds and incentive thresholds are based on assumptions that are inherently subjective and are subject to significant business, economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual cash distributions to differ materially from those estimated.

- Chesapeake may not serve as the operator of as many of the Developmental Wells as it expects and Chesapeake will rely upon unaffiliated third parties, who may be less qualified, to drill Development Wells where Chesapeake is not the operator.

- The oil, natural gas liquids and natural gas reserves estimated to be attributable to the Underlying Properties are depleting assets and production from those reserves will diminish over time. Furthermore, the trust is precluded from acquiring other oil and gas properties or royalty interests to replace the depleting assets and production.

- The hedging arrangements for the trust will cover only a portion of the production attributable to the trust, such arrangements will limit the trust s ability to benefit from commodity price increases for hedged volumes, and such arrangements will be secured by the trust s royalty interests in the Underlying Properties and may require the trust to make cash payments in excess of its receipts. Following this offering, except in limited circumstances involving the restructuring of an existing hedge, the trust will have no ability to terminate its hedging arrangements or enter into additional hedges. The hedging counterparties may foreclose on their lien on the trust s royalty interests in certain circumstances.

- Conflicts of interest could arise between Chesapeake and the trust.

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

The trust s tax treatment depends on its status as a partnership for U.S. federal income tax purposes. If the U.S. Internal Revenue Service (IRS) were to treat the trust as a corporation for U.S. federal income tax purposes or the trust were subjected to state or local entity level tax, then its cash available for distribution to unitholders would be substantially reduced.

The tax treatment of an investment in trust units could be affected by recent and potential legislative changes, possibly on a retroactive basis.

The trust will adopt positions that may not conform to all aspects of existing Treasury Regulations. If the IRS contests the tax positions the trust takes, the value of the trust units may be adversely affected, the cost of any IRS contest will reduce the trust s cash available for distribution and income, gain, loss and deduction may be reallocated among trust unitholders.

Table of Contents

Index to Financial Statements

Structure of the Trust

The following chart shows the relationship of Chesapeake, the trust and the public unitholders immediately following this offering (without giving effect to the exercise of the underwriters option to purchase additional common units).

* Chesapeake is expected to have an effective average net revenue interest of 29.0% in the Producing Wells and 39.0% in the Development Wells. Public unitholders (that is, holders of trust units other than Chesapeake) are expected to have an effective average net revenue interest of 23.8% in the Producing Wells and 13.0% in the Development Wells.

Table of Contents

Index to Financial Statements

The Offering

Common units offered to public	23,375,000 common units (26,881,250 common units, if the underwriters exercise their option to purchase additional common units in full)
Trust units owned by Chesapeake after the offering	11,687,500 common units and 11,687,500 subordinated units (8,181,250 common units and 11,687,500 subordinated units, if the underwriters exercise their option to purchase additional common units in full)
Total units outstanding after the offering	35,062,500 common units and 11,687,500 subordinated units
Option to purchase additional common units	3,506,250 common units will be issued and retained by the trust at the initial closing, to be used to satisfy (if necessary) the 30-day option to purchase additional units granted to the underwriters. If the underwriters exercise their option to purchase additional common units, the trust will sell to the underwriters such number of the retained units as is necessary to satisfy the option to purchase additional common units, and will then deliver the net proceeds of such sale, together with any remaining unsold units, to one or more subsidiaries of Chesapeake as partial consideration for the conveyance of the Perpetual Royalties. If the underwriters do not exercise their option to purchase additional common units, the retained units will be delivered to one or more subsidiaries of Chesapeake as partial consideration for the conveyance of the Perpetual Royalties, promptly following the 30th day after the date of this prospectus. See The Trust Formation Transactions beginning on page 45. The underwriters may exercise their option to purchase additional units solely for the purpose of covering over-allotments made in connection with the offering.
Use of proceeds	The trust is offering the common units to be sold in this offering. Assuming no exercise of the underwriters option to purchase additional common units and an initial public offering price of $20.00 per common unit (the midpoint of the price range set forth on the cover page of this prospectus), the estimated net proceeds of this offering will be approximately $435.7 million, after deducting underwriting discounts and commissions, the structuring fee and estimated offering expenses. The trust will deliver the net proceeds to a wholly owned subsidiary of Chesapeake, as consideration for the conveyance of the Term Royalties and as partial consideration for the conveyance of the Perpetual Royalties. See The Trust Formation Transactions beginning on page 45.
	Chesapeake intends to use any proceeds it receives from the sale of the royalty interests to the trust to repay borrowings under its credit facility. Chesapeake may re-borrow amounts under its credit facility from time to time and does so for general corporate purposes, including capital expenditures for land, drilling and other costs. See

	Use of Proceeds on page 43. Affiliates of certain of the underwriters are lenders under Chesapeake s credit facility and, in that respect, will receive a substantial portion of the proceeds from this offering through the repayment of borrowings outstanding under the facility. See Underwriting beginning on page 116.
NYSE symbol	CHKR
Trustee	The Bank of New York Mellon Trust Company, N.A.
Quarterly cash distributions	Quarterly cash distributions during the term of the trust will be made by the trustee approximately 60 days following the end of each calendar quarter to unitholders of record approximately 50 days following the end of each calendar quarter, except that the first distribution, which will cover the third quarter of 2011 (consisting of proceeds attributable to July and August 2011 production), is expected to be made on or about December 28, 2011 to record unitholders on or about December 15, 2011. The trustee intends to withhold $1.0 million from the first distribution to establish an initial cash reserve available for trust expenses. Thereafter, quarterly distributions will generally include royalties attributable to sales of oil, natural gas liquids and natural gas for three months, including the first two months of the quarter just ended and the last month of the quarter prior to that one.
	Actual cash distributions to the trust unitholders will fluctuate quarterly based on the quantity of oil, natural gas liquids and natural gas produced from the Underlying Properties, the prices received for such production, when Chesapeake receives payment for such production, payments under the hedge arrangements, the trust s administrative expenses and other factors. Because payments to the trust will be generated by depleting assets and production from the Underlying Properties will diminish over time, a portion of each distribution will represent a return of your original investment. Given that the production from the Underlying Properties is expected to initially increase and then subsequently decline over time, the target distributions are also expected to initially increase before declining over time.
Voting rights in the trust	Matters voted on by trust unitholders will generally be subject to approval by a majority of the common units (excluding common units owned by Chesapeake and its affiliates) and a majority of the trust units, in each case voting in person or by proxy at a meeting of such holders at which a quorum is present. Chesapeake and its affiliates will not be entitled to vote on the removal of the trustee or appointment of a successor trustee. However, if at any time Chesapeake and its affiliates own less than 10% of the outstanding trust units, matters voted on by trust unitholders will be subject to approval by a majority of the trust units, including units owned by Chesapeake, voting in person or by proxy at a meeting of such holders at which a quorum is present. The trust does not intend to hold annual meetings of the trust unitholders.

Table of Contents

Index to Financial Statements

Termination of the trust	The trust will dissolve and begin to liquidate on the Termination Date, which is June 30, 2031, and will soon thereafter wind up its affairs and terminate. At the Termination Date, the Term Royalties will revert automatically to Chesapeake. The Perpetual Royalties will be retained by the trust at the Termination Date and thereafter sold, and the net proceeds of the sale, as well as any remaining trust cash reserves, will be distributed to the unitholders pro rata. Chesapeake will have a right of first refusal to purchase the royalty interests retained by the trust at the Termination Date.
U.S. federal income tax considerations	The trust will be treated as a partnership for U.S. federal income tax purposes. Consequently, the trust will not incur any U.S. federal income tax liability. Instead, trust unitholders will be allocated an amount of the trust s income, gain, loss or deductions corresponding to their interest in the trust, which amounts may differ in timing or amount from actual cash distributions.
	The Term Royalty for the Producing Wells will and the Term Royalty for the Development Wells should be treated as debt instruments for U.S. federal income tax purposes. The trust will be required to treat a portion of each payment it receives with respect to each such royalty interest as interest income in accordance with the noncontingent bond method under the original issue discount rules contained in the Internal Revenue Code of 1986, as amended, and the corresponding IRS regulations.
	The Perpetual Royalty for the Producing Wells will and the Perpetual Royalty for the Development Wells should be treated as mineral royalty interests for U.S. federal income tax purposes, generating ordinary income subject to depletion.
	Please read U.S. Federal Income Tax Considerations beginning on page 98 for more information.
Estimated ratio of taxable income to distributions	The trust estimates that if you own the units you purchase in this offering through the record date for distributions for the period ending December 31, 2014, you will be allocated, on a cumulative basis, an amount of federal taxable income for that period that will be approximately 55% of the cash distributed to you with respect to that period. For example, if you receive an annual distribution of $1.00 per unit, the trust estimates that your average allocable federal taxable income per year will be approximately $0.55 per unit.
	Please read U.S. Federal Income Tax Considerations beginning on page 98 for more information.

[Table of Contents](#)

[Index to Financial Statements](#)

RISK FACTORS

Before making an investment decision, you should carefully consider the risks described below and the risks described in Chesapeake s Annual Report on Form 10-K for the year ended December 31, 2010, which is incorporated herein by reference. The trust s cash available for distribution could be materially adversely affected by any of these risks. The trading price of the common units could decline due to any of these risks, and you may lose all or part of your investment.

Risks Related to the Units

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

The drilling and completion of the Development Wells are subject to numerous risks beyond Chesapeake s and the trust s control, including risks that could delay or change the current drilling schedule for the Development Wells and the risk that drilling will not result in commercially viable oil, natural gas liquids and natural gas production. Drilling for oil, natural gas liquids and natural gas can be unprofitable if dry wells are drilled and if productive wells do not produce sufficient revenues to return a profit. Chesapeake s and third-party operators decisions to develop or otherwise exploit certain areas within the AMI will depend in part on the evaluation of data obtained through geophysical and geological analyses, production data and engineering studies, the results of which are often inconclusive or subject to varying interpretations. The costs of drilling, completing and operating wells are often uncertain before drilling commences. Overruns in budgeted expenditures could cause Chesapeake to re-direct its drilling capital to other plays and delay the drilling of the Development Wells beyond what was assumed in establishing target levels of cash distributions to unitholders. Drilling and production operations on the Underlying Properties may be curtailed, delayed or canceled as a result of various factors, including the following:

- delays imposed by or resulting from compliance with regulatory requirements, including permitting;
- unusual or unexpected geological formations and miscalculations or irregularities in formations;
- shortages of or delays in obtaining equipment and qualified personnel;
- equipment malfunctions, failures or accidents;
- lack of available gathering facilities or delays in construction of gathering facilities;
- lack of available capacity on interconnecting transmission pipelines;

unexpected operational events and drilling conditions;

pipe or cement failures and casing collapses;

pressures, fires, blowouts and explosions;

lost or damaged drilling and service tools;

loss of drilling fluid circulation;

lack of sufficient water or water disposal facilities in connection with hydraulic fracturing;

uncontrollable flows of oil, natural gas liquids and natural gas water or drilling fluids;

natural disasters;

environmental hazards, such as oil, natural gas liquids or natural gas leaks, pipeline ruptures and discharges of toxic gases or fluids;

adverse weather conditions, such as extreme cold, fires caused by extreme heat or lack of rain and severe storms or tornadoes;

Table of Contents

Index to Financial Statements

- reductions in oil, natural gas liquids and natural gas prices or, for hedged production, increases in pricing differentials; and
- title problems affecting the Underlying Properties.

If drilling of Development Wells is delayed or the Producing Wells or Development Wells have lower than anticipated production due to one of the factors above or for any other reason, cash distributions to unitholders may be reduced.

In addition, Development Wells may not be successful and Chesapeake is not obligated to drill replacement wells if this occurs. Under the Development Agreement, Chesapeake will receive credit for drilling a Development Well if the well is drilled in the AMI and perforated horizontally for completion in the Colony Granite Wash, even if such well does not successfully produce hydrocarbons. Additionally, once Chesapeake plugs and abandons an unsuccessful Development Well, that well will be released from the Drilling Support Lien.

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

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

- regional, domestic and foreign supply, and perceptions of supply, of oil, natural gas liquids and natural gas;
- the price and level of foreign imports of oil, natural gas liquids and natural gas, including political instability or armed conflict in producing regions;
- U.S. and worldwide political and economic conditions;
- the level of demand, and perceptions of demand, for oil, natural gas liquids and natural gas;
- weather conditions and seasonal trends;
- anticipated future prices of oil, natural gas liquids, natural gas, alternative fuels and other commodities;
- technological advances affecting energy consumption and energy supply;

- the proximity, capacity, cost and availability of pipeline infrastructure, treating, transportation and refining capacity;
- natural disasters;
- the nature and extent of domestic and foreign governmental regulations and taxation;
- energy conservation and environmental measures;
- the price and availability of alternative fuels and energy sources;
- the level and effect of trading in commodity futures markets, including by commodity price speculators and others; and
- the ability of the members of the Organization of Petroleum Exporting Countries to agree to and maintain oil price and production controls.

For oil, from 2007 through October 28, 2011, the highest monthly NYMEX settled price was $134.62 per bbl and the lowest was $33.87 per bbl. For natural gas, from 2007 through October 28, 2011, the highest monthly NYMEX settled price was $13.11 per mmbtu and the lowest was $2.84 per mmbtu. In addition, the market price of oil, natural gas liquids and natural gas is generally higher in the winter months than during other months of the year due to increased demand for oil, natural gas liquids and natural gas for heating purposes during the winter season.

Table of Contents

Index to Financial Statements

Lower oil, natural gas liquids and natural gas prices will reduce proceeds to which the trust is entitled and may ultimately reduce the amount of oil, natural gas liquids and natural gas that is economic to produce from the Underlying Properties. As a result, Chesapeake or any third-party operator of any of the Underlying Properties could determine during periods of low oil, natural gas liquids and natural gas prices to shut in or curtail production from wells on the Underlying Properties. In addition, the operator of the Underlying Properties could determine during periods of low oil, natural gas liquids and natural gas prices to plug and abandon marginal wells that otherwise may have been allowed to continue to produce for a longer period under conditions of higher prices. Specifically, Chesapeake or any third-party operator may abandon any well or property if it reasonably believes that the well or property can no longer produce oil, natural gas liquids and natural gas in commercially economic quantities. This could result in termination of the portion of the royalty interest relating to the abandoned well or property, and Chesapeake would have no obligation to drill a replacement well. The volatility of oil, natural gas liquids and natural gas prices also reduces the accuracy of target distributions to trust unitholders. There can be no assurance that the trust s hedging program will mitigate these risks. For a discussion of certain risks related to the trust s hedging arrangements, see The hedging arrangements for the trust will cover only a portion of the production attributable to the trust, such arrangements will limit the trust s ability to benefit from commodity price increases for hedged volumes, and such arrangements will be secured by the trust s royalty interests in the Underlying Properties and may require the trust to make cash payments in excess of its receipts beginning on page 28.

Actual reserves and future production may be less than current estimates, which could reduce cash distributions by the trust and the value of the trust units.

The value of the trust units and the amount of future cash distributions to the trust unitholders will depend upon, among other things, the accuracy of the future production estimated to be attributable to the trust s royalty interests. The future production estimates are based on estimates of reserve quantities for the Underlying Properties. See The Underlying Properties Oil, Natural Gas Liquids and Natural Gas Reserves beginning on page 69 for a discussion of the method of allocating proved reserves to the trust. It is not possible to measure underground accumulations of oil, natural gas liquids and natural gas in an exact way, and estimating reserves is inherently uncertain. Ultimately, actual production and revenues for the Underlying Properties could be materially less than estimated amounts. Petroleum engineers are required to make subjective estimates of underground accumulations of oil, natural gas liquids and natural gas based on factors and assumptions that include:

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

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

Reserve estimates for fields that do not have a lengthy production history are less reliable than estimates for fields with lengthy production histories. A lack of production history may contribute to inaccuracy in estimates of proved reserves, future production rates and the timing of development expenditures. Most of the Producing Wells have been operational for a relatively short period of time and estimated total reserves vary substantially from well to well and are not directly correlated to perforated lateral length or completion technique. There can be no assurance that the data used in preparing these estimates can accurately predict future production. The lack of operational history for horizontal wells in the Colony Granite Wash may also contribute to the inaccuracy of estimates of proved reserves. A material and adverse variance of actual production, revenues and expenditures from those underlying reserve estimates, would have a material adverse effect on the financial condition, results of operations and cash flows of the trust and would reduce cash distributions to trust unitholders.

Table of Contents

Index to Financial Statements

As with all horizontal drilling programs, there is a risk that some or all of a horizontal well could miss the target reservoir. As a result, the trust may not receive the benefit, or any revenue from, some or all of the proved undeveloped reserves reflected in the reserve reports, notwithstanding the fact that Chesapeake has satisfied its drilling obligation. See Summary The Development Wells beginning on page 4.

Estimates of the target distributions to unitholders, subordination thresholds and incentive thresholds are based on assumptions that are inherently subjective and are subject to significant business, economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual cash distributions to differ materially from those estimated.

The estimates of target distributions to unitholders, subordination thresholds and incentive thresholds, as set forth in this prospectus, have been established by Chesapeake, and Chesapeake has not received an opinion or report on such calculations from any independent accountants, financial advisers or engineers. Such estimates are based on assumptions about drilling, production, oil, natural gas liquids and natural gas prices, hedging activities, capital expenditures, expenses, tax rates and production tax credits under state law and other matters that are inherently uncertain and are subject to significant business, economic, financial, legal, regulatory and competitive risks and uncertainties that could cause actual results to differ materially from those estimated. For example, these estimates assume that oil, natural gas liquids and natural gas production is sold at prices consistent with spot and settled NYMEX pricing for July through November 2011, monthly NYMEX forward pricing as of October 28, 2011 for the remainder of the period ending June 30, 2014 and assumed price increases after June 30, 2014 of 2.5% annually, capped at $120.00 per bbl of oil (which cap would be reached in 2025) and $7.00 per mmbtu of natural gas (which cap would be reached in 2028); however, actual sales prices may not increase at this rate or at all and may instead decline, as they have recently. Additionally, these estimates assume that the Development Wells will be drilled on Chesapeake s current anticipated schedule and the related Underlying Properties will achieve production volumes set forth in the reserve reports; however, the drilling of the Development Wells may be delayed and actual production volumes may be significantly lower. Further, after wells are completed, production operations may be curtailed, delayed or terminated as a result of a variety of risks and uncertainties, including those described above under Drilling for and producing oil, natural gas liquids and natural gas on the Underlying Properties are high risk activities with many uncertainties that could delay the anticipated drilling schedule for the Development Wells and adversely affect future production from the Underlying Properties. Any such delays or reductions in production could decrease cash available for distribution to unitholders beginning on page 20.

Furthermore, neither the target distribution nor the subordination threshold for each quarter during the subordination period necessarily represents the actual cash distributions you will receive. To the extent actual production volumes or sales prices of oil, natural gas liquids and natural gas differ from the assumptions used to generate the target distributions, the actual distributions you receive may be lower than the target distribution and the subordination threshold for the applicable quarter. A cash distribution to trust unitholders below the target distribution amount or the subordination threshold may materially adversely affect the market price of the trust units.

The subordination of certain trust units held by Chesapeake does not ensure that you will in fact receive any specified return on your investment in the trust.

Although Chesapeake will not be entitled to receive any distribution on its subordinated units unless there is enough cash for all of the common units to receive a distribution equal to the subordination threshold for such quarter (which is 20% below the target distribution level for the corresponding quarter), the subordinated units constitute only a 25% interest in the trust, and this feature does not guarantee that common units will receive a distribution equal to the subordination threshold, or any distribution at all. Additionally, the subordination period will terminate and the subordinated units will convert into common units at the end of the fourth full calendar quarter following Chesapeake s completion of its drilling obligation. Depending on the prices at which Chesapeake is able to sell volumes attributable to the trust, the common units may receive a distribution that is below the subordination threshold.

Table of Contents

Index to Financial Statements

Quarterly cash distributions will be made by the trust based on the proceeds received by the trust pursuant to the royalty interests for the preceding calendar quarter. If a quarterly cash distribution is lower than the target distribution amount or subordination threshold set forth in this prospectus for any quarter, the common units will not be entitled to receive any additional distributions nor will the units be entitled to arrearages in any future quarter.

The historical and pro forma financial information included in this prospectus may not be representative of the trust s future distributable income.

The historical financial information included in this prospectus is derived from Chesapeake s historical financial statements for periods prior to the trust s formation or initial public offering. The historical financial information for the Underlying Properties included in this prospectus does not give effect to the terms and conditions of the royalty interests and, as a result, does not reflect what the trust s distributable income will be in the future.

In preparing the pro forma statements of distributable income included in this prospectus, Chesapeake has made adjustments to the historical pro forma financial information for the Underlying Properties based upon currently available information and upon assumptions that Chesapeake and the trust believe are reasonable in order to reflect, on a pro forma basis, the impact of the conveyance of the royalty interests to the trust and the other items discussed in the unaudited pro forma financial statements and related notes. The estimates and assumptions used in the calculation of the pro forma financial information in this prospectus may be materially different from the trust s actual experience. Accordingly, the pro forma financial information included in this prospectus does not purport to represent what the trust s distributable income would actually have been had it been in operation during the periods presented or what the trust s distributable income will be in the future, nor does the pro forma financial information give effect to any events other than those discussed in the unaudited pro forma financial statements and related notes.

Chesapeake may not serve as the operator of as many of the Developmental Wells as it expects and Chesapeake will rely upon unaffiliated third parties, who may be less qualified, to drill Development Wells where Chesapeake is not the operator.

Pursuant to the development agreement between Chesapeake and the trust, Chesapeake is obligated to drill, or cause to be drilled, 118 Development Wells in the AMI. Although Chesapeake expects to operate approximately 93% of the Development Wells until the completion of its drilling obligation, another working interest owner or a contract operator could serve as the operator for certain Development Wells. Chesapeake will rely upon these third-party operators to drill the Development Wells where it is not the operator. The ability of third-party operators to help Chesapeake meet the drilling obligation will depend on those operators future financial condition and economic performance and access to capital, which, in turn, will depend upon the supply and demand for oil, natural gas liquids and natural gas, prevailing economic conditions and financial, business and other factors. The failure of an operator to adequately perform operations could reduce production from the Underlying Properties and the cash available for distribution to trust unitholders. Chesapeake may be provided little or no notice by these operators that they are failing to drill the Development Wells in accordance with pre-existing schedules.

Because Chesapeake does not have a majority working interest in the non-operated properties comprising the Underlying Properties, Chesapeake may not be able to remove the operator in the event of poor or untimely performance. If the Development Wells take longer to be drilled than currently anticipated, this may delay revenue earned from the production of oil, natural gas liquids and natural gas by such wells. The revenues distributable to the trust and the amount of cash distributable to the trust unitholders would similarly be delayed.

Table of Contents

Index to Financial Statements

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

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

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

The demand for qualified and experienced personnel to conduct field operations, geologists, geophysicists, engineers and other professionals in the oil and gas industry can fluctuate significantly, often in correlation with oil, natural gas liquids and natural gas prices, causing periodic shortages. Historically, there have been shortages of drilling rigs and other equipment as demand for rigs and equipment has increased along with the number of wells being drilled. These factors also cause significant increases in costs for equipment, services and personnel. Higher oil, natural gas liquids and natural gas prices generally stimulate demand and result in increased prices for drilling rigs, crews and associated supplies, equipment and services. Shortages of field personnel and equipment or price increases could significantly hinder Chesapeake s ability to perform the drilling obligation and delay completion of the Development Wells, which would reduce future distributions to trust unitholders.

Due to the trust s lack of industry and geographic diversification, adverse developments in the trust s existing area of operation could adversely impact its financial condition, results of operations and cash flows and reduce its ability to make distributions to the unitholders.

The Underlying Properties will be operated for oil, natural gas liquids and natural gas production only and are focused exclusively in the Colony Granite Wash in Washita County in western Oklahoma. This concentration could disproportionately expose the trust s interests to operational and regulatory risk in that area. Due to the lack of diversification in industry type and location of the trust s interests, adverse developments in the oil, natural gas liquids and natural gas markets or the area of the Underlying Properties, including, for example, transportation or treatment capacity constraints, curtailment of production or treatment plant closures for scheduled maintenance, could have a significantly greater impact on the trust s financial condition, results of operations and cash flows than if the trust s royalty interests were more diversified.

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

The amount of oil, natural gas liquids and natural gas that may be produced and sold from any well to which the Underlying Properties relate is subject to the availability of gathering, transportation and processing facilities. Even where such facilities are available, services from such facilities are subject to curtailment in certain circumstances, such as by reason of weather conditions, pipeline interruptions due to scheduled and unscheduled maintenance, failure of tendered oil, natural gas liquids and natural gas to meet quality specifications of gathering lines or downstream transporters, excessive line pressure which prevents delivery or physical damage to the gathering system or transportation system. The curtailments may vary from a few days to several months. In many cases, Chesapeake or a third-party operator is provided limited notice, if any, as to when production will be curtailed and the duration of such curtailments. If Chesapeake or a third-party operator is forced to reduce production due to such a curtailment, the revenues of the trust and the amount of cash distributions to the trust unitholders would similarly be reduced due to the reduction of proceeds from the sale of production. Moreover, Chesapeake currently ships all of its natural gas production from the Underlying Properties to market through one pipeline provider and sells all of its oil production from the Underlying Properties to one purchaser. Although Chesapeake currently does not have any material production shut-in and does not shut in production on a routine basis as a result of lack of accessibility to transportation or lack of processing facilities, there can be no assurance this will be the case in the future.

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

The trust units may lose value and cash available for distribution may be reduced as a result of title deficiencies with respect to the Underlying Properties.

The existence of title deficiencies with respect to the Underlying Properties could reduce the value or render properties worthless, thus adversely affecting the distributions to unitholders. Chesapeake does not obtain title insurance covering oil, natural gas and mineral leaseholds. Additionally, undeveloped leasehold acreage has greater risk of title defects than developed acreage.

Prior to the drilling of a Development Well, Chesapeake intends to obtain a drilling title opinion to identify defects in title to the leasehold. Frequently, as a result of such examinations, certain curative work may be required to correct identified title defects, and such curative work entails time and expense. Chesapeake s inability or failure to cure title defects could render some locations undrillable or cause Chesapeake to lose its rights to some or all production from some of the Underlying Properties, which could result in a reduction in proceeds available for distribution to unitholders and the value of the trust units may be reduced.

The trust is passive in nature and will have no stockholder voting rights in Chesapeake, managerial, contractual or other ability to influence Chesapeake, or control over the field operations of, sale of oil, natural gas liquids and natural gas from, or development of, the Underlying Properties.

Trust unitholders have no voting rights with respect to Chesapeake securities and will have no managerial, contractual or other ability to influence Chesapeake s activities or operations of the Underlying Properties. In addition, some of the Development Wells will be operated by third parties unrelated to Chesapeake. Such third-party operators may not have the operational expertise of Chesapeake within the AMI. Oil and gas properties are typically managed pursuant to an operating agreement among the working interest owners in the properties. The typical operating agreement contains procedures whereby the owners of the aggregate working interest in the property designate one of the interest owners to be the operator of the property. Under these arrangements, the operator is typically responsible for making all decisions relating to drilling activities, sale of production, compliance with regulatory requirements and other matters that affect the property. Neither the trustee nor the trust unitholders has any contractual ability to influence or control the field operations of, sale of oil, natural gas liquids and natural gas from, or future development of, the Underlying Properties.

26

Table of Contents

Index to Financial Statements

The oil, natural gas liquids and natural gas reserves estimated to be attributable to the Underlying Properties are depleting assets and production from those reserves will diminish over time. Furthermore, the trust is precluded from acquiring other oil and gas properties or royalty interests to replace the depleting assets and production.

The proceeds payable to the trust from the royalty interests are derived from the sale of the production of oil, natural gas liquids and natural gas from the Underlying Properties. The oil, natural gas liquids and natural gas reserves attributable to the Underlying Properties are depleting assets, which means that the reserves of oil, natural gas liquids and natural gas attributable to the Underlying Properties will decline over time. As a result, the quantity of oil, natural gas liquids and natural gas produced from the Underlying Properties will decline over time.

Future maintenance may affect the quantity of proved reserves that can be economically produced from the Underlying Properties to which the wells relate. The timing and size of these projects will depend on, among other factors, the market prices of oil, natural gas liquids and natural gas. With the exception of Chesapeake s commitment to drill the Development Wells, Chesapeake has no contractual obligation to the trust to make capital expenditures on the Underlying Properties in the future. Furthermore, for properties on which Chesapeake is not designated as the operator, Chesapeake has no control over the timing or amount of those capital expenditures. Chesapeake also has the right not to participate in the capital expenditures on properties for which it is not the operator, in which case Chesapeake and the trust will not receive the production resulting from such capital expenditures. If Chesapeake or other operators of the wells to which the Underlying Properties relate do not implement maintenance projects when warranted, the future rate of production decline of proved reserves may be higher than the rate currently expected by Chesapeake or estimated in the reserve reports.

The trust agreement will provide that the trust s business activities will generally be limited to owning the royalty interests and entering into the hedging agreements and activities reasonably related thereto, including activities required or permitted by the terms of the conveyances related to the royalty interests. As a result, the trust will not be permitted to acquire other oil and gas properties or royalty interests to replace the depleting assets and production attributable to the trust.

An increase in the differential between the price realized by Chesapeake for oil, natural gas liquids and natural gas produced from the Underlying Properties and the NYMEX or other benchmark price of oil or natural gas could reduce the proceeds to the trust and therefore the cash distributions by the trust and the value of trust units.

The prices received for Chesapeake s oil, natural gas liquids and natural gas production in Oklahoma usually fall below benchmark prices, such as NYMEX. The difference between the price received and the benchmark price is called a differential. The amount of the differential will depend on a variety of factors, including discounts based on the quality and location of hydrocarbons produced, btu content, post-production expenses and severance taxes. These factors can cause differentials to be volatile from period to period. Chesapeake has little or no control over the factors that determine the amount of the differential, and cannot accurately predict natural gas or crude oil differentials. Increases in the differential between the realized price of oil, natural gas liquids and natural gas and the benchmark price for oil, natural gas liquids and natural gas could reduce the proceeds to the trust and therefore the cash distributions by the trust and the value of the trust units. For information on the differentials assumed for purposes of preparing the target distributions, see Target Distributions and Subordination and Incentive Thresholds Significant Assumptions Used to Calculate the Target Distributions beginning on page 58.

Table of Contents

Index to Financial Statements

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

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

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

- the trust s share of applicable taxes on the oil, natural gas liquids and natural gas;

- trust administrative expenses, including fees paid to the trustee and the Delaware trustee, the annual administrative services fee payable to Chesapeake, tax return and Schedule K-1 preparation and mailing costs, independent auditor fees and registrar and transfer agent fees, costs associated with annual and quarterly reports to unitholders and certain internal expenses of the trust incurred pursuant to the registration rights agreement; and

- any amounts owed to counterparties under the trust s hedging arrangements.

In addition, the amount of funds available for distribution to unitholders will be reduced by the amount of any cash reserves maintained by the trustee in respect of anticipated future trust expenses.

Further, during the subordination period, Chesapeake will be entitled to receive a quarterly incentive distribution from the trust equal to 50% of the amount by which cash available to be paid to all unitholders exceeds the incentive threshold for the applicable quarter. See Target Distributions and Subordination and Incentive Thresholds beginning on page 52.

The amount of costs and expenses borne by the trust may vary materially from quarter to quarter. The extent by which the costs and expenses of the trust are higher or lower in any quarter will directly decrease or increase the amount received by the trust and available for distribution to the unitholders. For a further summary of post-production expenses and applicable taxes for the producing lives of the Producing Wells and Development Wells, see The Underlying Properties beginning on page 66. Historical post-production expenses and taxes, however, may not be indicative of future post-production expenses and taxes.

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

The trust will be a party to oil and natural gas liquids hedging arrangements pursuant to which the trust will hedge approximately 50% of the expected oil and natural gas liquids production and 37% of the trust s expected revenues (based on NYMEX strip oil prices as of October 28,

2011) upon which the target distributions from October 1, 2011 through September 30, 2015 are based. Estimated production of natural gas liquids will be hedged using a conversion ratio of one barrel of natural gas liquids to 49.2% of a barrel of oil, which ratio may not be consistent with the market conversion ratio in the future. Except in limited circumstances involving the restructuring of an existing hedge, the remaining estimated production of oil and natural gas liquids and all production of natural gas from October 1, 2011 through September 30, 2015 will not be hedged and the trust will not have the ability to enter into additional hedges, terminate existing hedges or hedge production beyond September 30, 2015. With respect to unhedged volumes and periods, the trust will not be protected against the price risks inherent in holding interests in oil, natural gas liquids and natural gas, commodities that are frequently characterized by significant price volatility. Furthermore, while the use of hedging arrangements limits the downside risk of price declines, they may also limit the trust s ability to benefit from increases in oil and natural gas liquids prices above the hedge price on the portion of the production attributable to the trust s royalty interests that is hedged.

Table of Contents

Index to Financial Statements

Chesapeake will act as hedge manager to the trust pursuant to the administrative services agreement. In fulfilling its role as hedge manager, Chesapeake will not act as a fiduciary for the trust, will have no affirmative duty to modify any of the trust s hedges except as required by the hedging arrangements, and will have no liability to the trust in connection with Chesapeake s failure to modify, or any affirmative modification of, any of the trust s hedges. Moreover, Chesapeake will be indemnified by the trust for any actions it takes in this regard.

The trust s receipt of any payments due to it based on the trust s hedging arrangements depends upon the financial position of the hedge counterparties. If any of the counterparties to the oil and natural gas liquids hedging arrangements were to default on their obligations to make payments under such contracts, the cash distributions to the trust unitholders would likely be materially reduced as the hedge payments are intended to provide additional cash to the trust during periods of lower oil and natural gas liquids prices.

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

Under the hedging arrangements and separate from the drilling obligation of Chesapeake under the development agreement, there is a requirement that Chesapeake drill and complete a specified number of Development Wells by the end of each six-month period ending June 30 and December 31 during the term of the hedging arrangements. In addition, with respect to each such six