BP PRUDHOE BAY ROYALTY TRUST
Form 10-K
March 01, 2013
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UNITED STATES

SECURITIES AND EXCHANGE COMMISSION

Washington, D.C. 20549

FORM 10-K

x **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the Fiscal Year ended December 31, 2012

OR

¨ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

Commission File Number 1-10243

BP PRUDHOE BAY ROYALTY TRUST

(Exact name of registrant as specified in its charter)

DELAWARE	**13-6943724**
State or other jurisdiction of	**(I.R.S. Employer**
incorporation or organization)	**Identification No.)**

THE BANK OF NEW YORK MELLON

TRUST COMPANY, N.A., TRUSTEE

919 CONGRESS AVE.

AUSTIN, TEXAS	**78701**
(Address of principal executive offices)	**(Zip Code)**

Registrant s telephone number, including area code: (512) 236-6565

Securities registered pursuant to Section 12(b) of the Act:

Title of Each Class	**Name of Each Exchange on Which Registered**
UNITS OF BENEFICIAL INTEREST	**NEW YORK STOCK EXCHANGE**

Securities registered pursuant to Section 12(g) of the Act: NONE

Indicate by check mark if the registrant is a well-known seasoned issuer, as defined in Rule 405 of the Securities Act. Yes x No ¨

Indicate by check mark if the registrant is not required to file reports pursuant to Section 13 or Section 15(d) of the Act. Yes ¨ No x

Indicate by check mark whether the registrant: (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months (or for such shorter period that the registrant was required to file such reports), and (2) has been subject to such filing requirements for the past 90 days. Yes x No ¨

Indicate by check mark whether the registrant has submitted electronically and posted on its corporate Web site, if any, every Interactive Data File required to be submitted and posted pursuant to Rule 405 of Regulation S-T (17 CFR § 232.405) during the preceding 12 months (or for such shorter period that the registrant was required to submit and post such files). Yes ¨ No ¨

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of registrant s knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. x

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):

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

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

The aggregate market value of Units held by nonaffiliates (computed by reference to the closing sale price in New York Stock Exchange transactions on June 30, 2012 (the last business day of the registrant s most recently completed second fiscal quarter)) was approximately $2,494,598,000.

As of February 28, 2013, 21,400,000 Units of Beneficial Interest were outstanding.

DOCUMENTS INCORPORATED BY REFERENCE

None

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PART I

ITEM 1. BUSINESS

INTRODUCTION

BP Prudhoe Bay Royalty Trust (the Trust) was created as a Delaware business trust by the BP Prudhoe Bay Royalty Trust Agreement dated February 28, 1989 (the Trust Agreement) among The Standard Oil Company (Standard Oil), BP Exploration (Alaska) Inc. (BP Alaska), The Bank of New York Mellon (formerly named The Bank of New York), as trustee, and F. James Hutchinson, co-trustee (BNY Mellon Trust of Delaware, formerly named The Bank of New York (Delaware), successor co-trustee). BP Alaska and Standard Oil are wholly owned subsidiaries of BP p.l.c. (BP).

Effective as of December 15, 2010, The Bank of New York Mellon (BNYM) resigned as trustee under the Trust Agreement and BP Alaska appointed The Bank of New York Mellon Trust Company, N.A. (the Trust Company) to succeed BNYM as trustee. The Trust Company accepted its appointment and assumed all rights, titles, duties, powers and authority formerly held and exercised by BNYM under the Trust Agreement. The corporate trust office of the Trust Company (which we refer to hereafter as the Trustee) at which the affairs of the Trust are administered is located at 919 Congress Avenue, Austin, Texas 78701 and its telephone number at that address is (512) 236-6565.

The Trust electronically files annual reports on Form 10-K, quarterly reports on Form 10-Q and, when certain events require them, current reports on Form 8-K with the Securities and Exchange Commission (SEC). The public may read and copy any materials filed by the Trust with the SEC at the SEC s Public Reference Room at 100 F Street, N.E., Washington, D.C. 20549. The public may obtain information on the operation of the Public Reference Room by calling the SEC at 1-800-SEC-0330. The SEC also maintains an Internet site that contains reports, proxy and information statements, and other information regarding issuers (including the Trust) that file electronically with the SEC. The address of the SEC s website is http://www.sec.gov.

The Trust does not maintain an Internet website, but certain information concerning the Trust and the Trust Units may be obtained from the BusinessWire website at the following page location: http://bpt.investorhq.businesswire.com. The Trustee will provide paper or electronic copies of the Trust s reports on Form 10-K, Form 10-Q and Form 8-K, and amendments to those reports, free of charge upon request as soon as reasonably practicable after the Trust files them with the SEC. Requests for copies of reports may be made by mail to: The Bank of New York Mellon Trust Company, N.A., 919 Congress Avenue, Suite 500, Austin, TX 78701, Attention: Global Corporate Trust Corporate Finance; by telephone to: (800) 852-1422; or by e-mail to: maryjo.davis@bnymellon.com.

The information in this report relating to the Prudhoe Bay Unit, the calculation of royalty payments and certain other matters has been furnished to the Trustee by BP Alaska.

Forward-Looking Statements

Various sections of this report contain forward-looking statements (that is, statements anticipating future events or conditions and not statements of historical fact). Words such as anticipate, expect, believe, intend, plan or project, and should, would, could, potentially, p other words that convey uncertainty of future events or outcomes are intended to identify forward-looking statements. Forward-looking statements in this report are subject to a number of risks and uncertainties beyond the control of the Trustee. These risks and uncertainties include such matters as future changes in oil prices, oil production levels, economic activity, domestic and international political events and developments, legislation and regulation, and certain changes in expenses of the Trust.

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The actual results, performance and prospects of the Trust could differ materially from those expressed or implied by forward-looking statements. Descriptions of some of the risks that could affect the future performance of the Trust appear in the following Item 1A, RISK FACTORS, and elsewhere in this report. There may be additional risks of which the Trustee is unaware or which are currently deemed immaterial.

In the light of these risks, uncertainties and assumptions, you should not rely unduly on any forward-looking statements. Forward-looking events and outcomes discussed in this report may not occur or may turn out differently. The Trustee undertakes no obligation to update forward-looking statements after the date of this report, except as required by law, and all such forward-looking statements in this report are qualified in their entirety by the preceding cautionary statements.

THE TRUST

Trust Property

The property of the Trust consists of an overriding royalty interest (the Royalty Interest) and cash and cash equivalents held by the Trustee from time to time. The Royalty Interest entitles the Trust to a royalty on 16.4246% of the lesser of (i) the first 90,000 barrels* of the average actual daily net production of crude oil and condensate per quarter from the working interest of BP Alaska as of February 28, 1989 in the Prudhoe Bay oil field located on the North Slope in Alaska or (ii) the average actual daily net production of crude oil and condensate per quarter from that working interest. The Prudhoe Bay field is one of four contiguous North Slope oil fields that are operated by BP Alaska and are known collectively as the Prudhoe Bay Unit. The Royalty Interest was conveyed to the Trust by an Overriding Royalty Conveyance dated February 27, 1989 from BP Alaska to Standard Oil and a Trust Conveyance dated February 28, 1989 from Standard Oil to the Trust. Copies of the Overriding Royalty Conveyance and the Trust Conveyance are filed with the SEC as exhibits to this report. The Overriding Royalty Conveyance and the Trust Conveyance are referred to collectively in this report as the Conveyance.

The Royalty Interest is a non-operational interest in minerals. The Trust does not have the right to take oil and gas in kind, nor does it have any right to take over operations or to share in any operating decision with respect to BP Alaska s working interest in the Prudhoe Bay field. BP Alaska is not obligated to continue to operate any well or maintain or attempt to maintain in force any portion of its working interest when, in its reasonable and prudent business judgment, the well or interest ceases to produce or is not capable of producing oil or gas in paying quantities.

Employees

The Trust has no employees. All administrative functions of the Trust are performed by the Trustee.

Duties and Powers of the Trustee

The duties of the Trustee are specified in the Trust Agreement and the laws of the State of Delaware. BNY Mellon Trust of Delaware has been appointed co-trustee in order to satisfy the Delaware Statutory Trust Act s requirement that the Trust have at least one trustee resident in, or which has its principal place of business in, Delaware. However, The Bank of New York Mellon Trust Company, N.A. alone is able to exercise the rights and powers granted to the Trustee in the Trust Agreement. A copy of the Trust Agreement is filed with the SEC as an exhibit to this report.

* The term barrel is a unit of measure of petroleum liquids equal to 42 United States gallons corrected to 60 degrees Fahrenheit temperature.

The basic function of the Trustee is to collect income from the Royalty Interest, to pay all expenses, charges and obligations of the Trust from the Trust s income and assets, and to pay available cash to Unit holders. Because of the passive nature of the Trust s assets and the restrictions on the power of the Trustee to incur obligations, the only liabilities that the Trust normally incurs in the conduct of its operations are the Trustee s fees and routine administrative expenses, including accounting, legal and other professional fees.

The Trust Agreement grants the Trustee only the rights and powers necessary to achieve the purposes of the Trust. The Trust Agreement prohibits the Trust from engaging in any business or commercial activity or, with certain exceptions, any investment activity and from using any assets of the Trust to acquire any oil and gas lease, royalty or other mineral interest.

The Trustee is entitled to be indemnified out of the assets of the Trust for any liability or loss incurred by it in the performance of its duties unless the loss results from its negligence, bad faith or fraud or from expenses incurred in carrying out its duties that exceed the compensation and reimbursement to which it is entitled under the Trust Agreement.

Sales of Royalty Interest; Borrowings and Reserves

With certain exceptions, the Trustee may sell all or part of the Royalty Interest or an interest therein only if authorized to do so by vote of the holders of 60% of the Units outstanding. However, if the sale is made in order to pay specific liabilities of the Trust then due and involves a part, but not all or substantially all, of the Trust properties, the sale only needs to be approved by the vote of holders of a majority of the Units. Any sale of Trust properties must be for cash unless otherwise authorized by the Unit holders. The Trustee is obligated to distribute the available net proceeds of any such sale to the Unit holders after establishing reserves for liabilities of the Trust.

The Trustee has the power to borrow on behalf of the Trust or to sell Trust assets to pay liabilities of the Trust and to establish a reserve for the payment of liabilities without the consent of the Unit holders under the following circumstances:

The Trustee may borrow from a lender not affiliated with the Trustee if cash on hand is not sufficient to pay current liabilities and the Trustee has determined that it is not practical to pay such liabilities out of funds anticipated to be available in subsequent quarters and that, without such borrowing, the Trust property is subject to the risk of loss or diminution in value. To secure payment of its borrowings on behalf of the Trust, the Trustee is authorized to encumber the Trust s assets and to carve out and convey production payments. The borrowing must be on terms which (in the opinion of an investment banking firm or commercial banking firm selected by the Trustee) are commercially reasonable when compared to other available alternatives. No distributions to Unit holders may be made until the borrowings by the Trust have been repaid in full.

If the Trustee is unable to borrow to pay Trust liabilities, the Trustee may sell Trust assets if it determines that the failure to pay the liabilities at a later date will be contrary to the best interest of the Unit holders and that it is not practicable to submit the sale to a vote of the Unit holders. The sale must be made for cash at a price which (in the opinion of an investment banking firm or commercial banking firm selected by the Trustee) is at least equal to the fair market value of the interest sold and is made on commercially reasonable terms when compared to other available alternatives.

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The Trustee has the right to establish a cash reserve for the payment of material liabilities of the Trust which may become due if it determines that it is not practical to pay such liabilities out of funds anticipated to be available in subsequent quarters and that, in the absence of a reserve, the Trust property is subject to the risk of loss or diminution in value or the Trustee is subject to the risk of personal liability for such liabilities.

In order for the Trustee to borrow, sell assets to pay Trust liabilities or establish a reserve for Trust liabilities, the Trustee must receive an unqualified written legal opinion that the contemplated action will not adversely affect the classification of the Trust as a grantor trust for federal income tax purposes or cause the income from the Trust to be treated as unrelated business taxable income for federal income tax purposes. If the Trustee is unable to obtain the required legal opinion, it still may proceed with the borrowing or sale, or establish the reserve, if it determines that the failure to do so will be materially detrimental to the Unit holders considered as a whole.

The Trustee maintains a $1,000,000 cash reserve to provide liquidity to the Trust during any periods in which the Trust does not receive a distribution from BP Alaska. See Item 7 in Part II below.

Irrevocability; Amendment of the Trust Agreement

The Trust Agreement and the Trust are irrevocable. No person has the power to terminate, revoke or change the Trust Agreement except as described in the following paragraph and below under Termination of the Trust.

The Trust Agreement may be amended without a vote of the Unit holders to cure an ambiguity, to correct or supplement any provision of the Trust Agreement that may be inconsistent with any other provision or to make any other provision with respect to matters arising under the Trust Agreement that does not adversely affect the Unit holders. The Trust Agreement also may be amended with the approval of holders of a majority of the outstanding Units. However, no such amendment may alter the relative rights of Unit holders unless approved by the affirmative vote of holders of 100% of the outstanding Units, nor may any amendment reduce or delay the distributions to the Unit holders, alter the voting rights of Unit holders or the number of Units in the Trust, or make certain other changes, unless approved by the affirmative vote of holders of at least 80% of the outstanding Units and by the Trustee. The Trustee is required to consent to any amendment approved by the requisite vote of Unit holders unless the amendment affects the Trustee s rights, duties and immunities under the Trust Agreement. No amendment will be effective until the Trustee has received a ruling from the Internal Revenue Service or an opinion of counsel to the effect that such modification will not adversely affect the classification of the Trust as a grantor trust for federal income tax purposes or cause the income from the Trust to be treated as unrelated business taxable income for federal income tax purposes.

Termination of the Trust

The Trust will terminate if either (a) holders of at least 60% of the outstanding Units vote to terminate the Trust or (b) the net revenues from the Royalty Interest for two successive years are less than $1,000,000 per year (unless the net revenues during the two-year period have been materially and adversely affected by certain extraordinary events).

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Upon termination of the Trust, BP Alaska will have an option to purchase the Royalty Interest at a price equal to the greater of (i) the fair market value of the Trust property as set forth in an opinion of an investment banking firm, commercial banking firm or other entity qualified to give an opinion as to the fair market value of the assets of the Trust, or (ii) the number of outstanding Units multiplied by (a) the closing price of Units on the day of termination of the Trust on the stock exchange on which the Units are listed, or (b) if the Units are not listed on any stock exchange but are traded in the over-the-counter market, the closing bid price on the day of termination of the Trust as quoted on the NASDAQ Stock Market. The purchase must be for cash unless holders of 60% of the Units outstanding authorize the sale for non-cash consideration and the Trustee has received a ruling from the Internal Revenue Service or an opinion of counsel to the effect that such non-cash sale will not adversely affect the classification of the Trust as a grantor trust for federal income tax purposes or cause the income from the Trust to be treated as unrelated business taxable income for federal income tax purposes.

If BP Alaska does not exercise its option, the Trustee will sell the Trust property on terms and conditions approved by the vote of holders of 60% of the outstanding Units, unless the Trustee determines that it is not practicable to submit the matter to a vote of the Unit holders and the sale is made at a price at least equal to the fair market value of the Trust property as set forth in the opinion of the investment banking firm, commercial banking firm or other entity mentioned above and on terms and conditions deemed commercially reasonable by that firm.

The Trustee will distribute all available proceeds to the Unit holders after satisfying all existing liabilities of the Trust and establishing adequate reserves for the payment of contingent liabilities.

Unit holders do not have the right under the Trust Agreement to seek or secure any partition or distribution of the Royalty Interest or any other asset of the Trust or any accounting during the term of the Trust or during any period of liquidation and winding up.

Resignation or Removal of Trustee

The Trustee may resign at any time or be removed with or without cause by vote of the holders of a majority of the outstanding Units at a meeting called and held in accordance with the Trust Agreement. A successor trustee may be appointed by BP Alaska or, if the Trustee has been removed at a meeting of the Unit holders, the successor trustee may be appointed by the Unit holders at the meeting. Any successor trustee must be a corporation organized, doing business and authorized to exercise trust powers under the laws of the United States, any state thereof or the District of Columbia, or a national banking association domiciled in the United States, in either case having a combined capital, surplus and undivided profits of at least $50,000,000 and subject to supervision or examination by federal or state authorities. Unless the Trust already has a trustee that is a resident of or has a principal office in Delaware, any successor trustee must be a resident of Delaware or have a principal office in Delaware. No resignation or removal of the Trustee will become effective until a successor trustee has accepted appointment.

Voting Rights of Unit Holders

Unit holders possess certain voting rights, but their voting rights are not comparable to those of shareholders of a corporation. For example, there is no requirement for annual meetings of Unit holders or for periodic reelection of the Trustee.

A meeting of the Unit holders may be called at any time to act with respect to any matter as to which the Trust Agreement authorizes the Unit holders to act. Any such meeting may be called by the Trustee in its discretion and will be called by the Trustee (i) as soon as practicable after receipt of a written request by BP Alaska or a written request that sets forth in reasonable detail the action proposed to be taken at the meeting and is signed by holders of at least 25% of the outstanding Units or (ii) when required by applicable laws or regulations or the New York Stock Exchange. The Trustee will give written notice of any meeting stating the time and place of the meeting and the matters to be acted on not more than 60 days nor fewer than 10 days before the meeting to all Unit holders of record on a date not more than 60 days before the meeting at their addresses shown on the records of the Trust. All meetings of Unit holders are required to be held in Manhattan, New York City. Unit holders are entitled to cast one vote on all matters coming before a meeting, in person or by proxy, for each Unit held on the record date for the meeting.

THE ROYALTY INTEREST

The Royalty Interest is a property right under Alaska law which burdens production, but there is no other security interest in the reserves or production revenues assigned to it. The royalty payable to the Trust for each calendar quarter is the sum of the amounts obtained by multiplying Royalty Production for each day in the calendar quarter by the Per Barrel Royalty for that day. The payment under the Royalty Interest for any calendar quarter may not be less than zero nor more than the aggregate value of the total production of oil and condensate from BP Alaska s working interest in the Prudhoe Bay Unit for the quarter, net of the State of Alaska royalty and less the value of any applicable payments made to affiliates of BP Alaska.

Royalty Production

The Royalty Production for each day in a calendar quarter is 16.4246% of the lesser of (i) the first 90,000 barrels of the actual average daily net production of crude oil and condensate for the quarter from the Prudhoe Bay (Permo-Triassic) Reservoir and saved and allocated to the oil and gas leases owned by BP Alaska in the Prudhoe Bay field as of February 28, 1989 (the 1989 Working Interests), or (ii) the actual average daily net production of crude oil and condensate for the quarter from the 1989 Working Interests. The Royalty Production is based on oil produced from the oil rim and condensate produced from the gas cap, but not on gas production or natural gas liquids production. The actual average daily net production of oil and condensate from the 1989 Working Interests for any calendar quarter is the total production of oil and condensate for the quarter, net of the State of Alaska royalty, divided by the number of days in the quarter.

Per Barrel Royalty

The Per Barrel Royalty for any day is the WTI Price for the day less the sum of (i) Chargeable Costs multiplied by the Cost Adjustment Factor and (ii) Production Taxes.

WTI Price

The WTI Price for any trading day is (i) the price (in dollars per barrel) for West Texas intermediate crude oil of standard quality having a specific gravity of 40 API degrees for delivery at Cushing, Oklahoma (West Texas Intermediate) quoted for that trading day by whichever of The Wall Street Journal, Reuters, or Platts Oilgram Price Report, in that order, publishes West Texas Intermediate price quotations for the trading day, or (ii) if the price of West Texas Intermediate is not published by one of those publications, the WTI Price will be the simple average of the daily mean prices (in dollars per barrel) quoted for West Texas Intermediate by one major oil company, one petroleum broker and one petroleum trading company designated by BP Alaska, in each case unaffiliated with BP and having substantial U.S. operations, until published price quotations are again available. If prices for West Texas Intermediate are not quoted so as to permit the calculation of the WTI Price, the price of West Texas Intermediate, for the purposes of calculating the WTI Price will be the price of another light sweet domestic crude oil of standard quality designated by BP Alaska and approved by the Trustee, with appropriate allowance for transportation costs to the Gulf coast (or another appropriate location) to equilibrate its price to the WTI Price. The WTI Price for any day which is not a trading day is the WTI Price for the preceding trading day.

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Chargeable Costs

The Chargeable Costs per barrel of Royalty Production for each calendar year are fixed amounts specified in the Conveyance and do not necessarily represent BP Alaska s actual costs of production. Chargeable Costs per barrel were $13.00 during 2008, $13.25 during 2009, $14.50 during 2010, $16.60 during 2011 and $16.70 during 2012. Chargeable Costs for 2013 and subsequent years are shown in the following table:

Calendar year	Chargeable Costs per barrel	Calendar year	Chargeable Costs per barrel
2013	$ 16.80	2018	$ 20.00
2014	16.90	2019	23.75
2015	17.00	2020	26.50
2016	17.10		
2017	17.20		

After 2020, Chargeable Costs increase at a uniform rate of $2.75 per barrel per year.

Cost Adjustment Factor

The Cost Adjustment Factor for a quarter is the ratio of the Consumer Price Index published for the most recently past February, May, August or November to 121.1 (the Consumer Price Index for January 1989). The Consumer Price Index is the U.S. Consumer Price Index, all items and all urban consumers, U.S. city average (1982-84 equals 100), as first published, without seasonal adjustment, by the Bureau of Labor Statistics, Department of Labor, without regard to subsequent revisions or corrections. If the average WTI Price for any calendar quarter falls to $18.00 or less, the Cost Adjustment Factor for that quarter will be the Cost Adjustment Factor for the immediately preceding quarter. If the average WTI Price returns to more than $18.00 for a later quarter, adjustments to the Cost Adjustment Factor resume, but with an adjustment to the formula that excludes changes in the Consumer Price Index during the period that adjustments to the Cost Adjustment Factor were suspended.

Production Taxes

Production Taxes are the sum of any severance taxes, excise taxes (including windfall profit tax, if any), sales taxes, value added taxes or other similar or direct taxes imposed upon the reserves or production, delivery or sale of Royalty Production, computed at defined statutory rates.

Until August 2006, the Production Taxes deductible with respect to the Royalty Production under the Alaska oil and gas production tax statutes, AS 43.55.10 *et seq.* (the Production Tax Statutes) were (i) the Alaska Oil Production Tax (the Old Tax), which was levied at the flat rate of 15% of the gross value of oil at the point of production (the wellhead or field value) and which, as required by the Conveyance, was applied for the purpose of determining the Royalty Interest without regard to the economic limit factor (a formula designed to result in low tax rates for smaller low productive fields and higher tax rates for larger highly productive fields), and (ii) a surcharge of $0.03 per barrel of Royalty Production. The Conveyance provides that, in the case of taxes based upon wellhead or field value, the WTI Price less the product of $4.50 multiplied by the Cost Adjustment Factor is deemed to be the wellhead or field value.

In August 2006 Alaska adopted amendments to the Production Tax Statutes (Chapter 2, Third Special Session Laws of Alaska 2006) (the 2006 Amendments) which replaced the Old Tax. Commencing with the 2006 Amendments, producers were taxed on the production tax value of taxable oil (gross value at the point of production for the calendar year less the producer s direct costs of exploring for, developing, or producing oil or gas deposits located within the producer s leases or properties in Alaska (Lease Expenditures) for the year) at a rate equal to the sum of 22.5% plus a progressivity rate determined by the average monthly production tax value of the oil produced. The progressivity portion of the 2006 Amendments was equal to 0.25% times the amount by which the simple average for each calendar month of the daily production tax values per barrel of the oil produced during the month exceeded $40 per barrel. In addition, the 2006 Amendments increased the surcharge on oil produced from leases or properties in Alaska from $0.03 to $0.04 per barrel.

In December 2007, a bill (Chapter 1, Second Special Session Laws of Alaska 2007) (popularly titled Alaska s Clear and Equitable Share or ACES) took effect and further amended the Production Tax Statutes in certain respects. ACES changed the basic tax rate from 22.5% to 25% and increased the progressivity rate. If the producer s average monthly production tax value per barrel is greater than $30 but not more than $92.50, the progressivity tax rate is 0.4% times the amount by which the average monthly production tax value exceeds $30 per barrel. If the producer s average monthly production tax value per barrel is greater than $92.50, the progressivity tax rate is the sum of 25% and the product of 0.1% multiplied by the difference between the average monthly production tax value per barrel and $92.50, except that the sum may not exceed 50%.

In order to resolve uncertainties in the interpretation of the Conveyance resulting from adoption of the 2006 Amendments, in October 2006 the Trustee entered into a letter agreement with BP Alaska (the 2006 Letter Agreement), a copy of which is incorporated by reference as Exhibit 4.5 to this report. The 2006 Letter Agreement sets forth principles agreed to by BP Alaska and the Trustee to resolve how the amount of tax chargeable against the Royalty Interest was to be determined under the Conveyance and the extent to which the retroactivity of the tax legislation was to be recognized for purposes of the Conveyance (the Consensus Principles). In December 2007, BP Alaska notified the Trustee that the adoption of ACES made it necessary to modify the Consensus Principles to give effect to the new tax rates. After determining that the proposed changes to the Consensus Principles were consistent with the changes in tax rates effected by ACES, on January 11, 2008 the Trustee executed a letter agreement dated December 21, 2007 with BP Alaska (the 2008 Letter Agreement) which supplements and amends the 2006 Letter Agreement and which is incorporated by reference as Exhibit 4.6 to this report.

ACES authorizes the Alaska Department of Revenue (DOR) to interpret and apply the amendments to the Production Tax Statutes. DOR is allowed to limit deductible transportation costs for transportation by a regulated pipeline to something less than the tariff actually paid. Other amendments allow DOR to exclude by regulation certain categories of otherwise deductible lease expenditures, or a fixed percentage of them, from being deductible in determining the production tax value of taxable oil. In the 2008 Letter Agreement, BP Alaska indicated that, depending on what the regulations provide, it may wish to amend the Consensus Principles. Any such amendment would require the consent of the Trustee. If any such amendment should be proposed, the Trustee will evaluate the proposal to determine whether such amendment is consistent with the Conveyance and the interests of the Unit holders of the Trust and will make its decision accordingly.

Per Barrel Royalty Calculations

The following table shows how the above-described factors interacted during the past five years to produce the average Per Barrel Royalty paid during the calendar years indicated. Royalty revenues are generally received on the fifteenth day of the month following the end of the calendar quarter in which

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the related Royalty Production occurred. Revenues and expenses presented in the statement of cash earnings and distributions presented in Part II, Item 8 below are recorded on a modified cash basis and, as a result, royalty revenues and distributions shown in such statements for any calendar year are attributable to BP Alaska s operations during the twelve-month period ended September 30 of that year.

	Average WTI Price	Chargeable Costs	Cost Adjustment Factor	Adjusted Chargeable Costs	Production Taxes(1)	Average Per Barrel Royalty
Calendar 2008:						
4th Qtr 2007	$ 90.93	$ 12.75	1.618	$ 20.63	$ 22.29	$ 48.01
1st Qtr 2008	97.78	13.00	1.630	21.19	33.58	43.01
2nd Qtr 2008	124.34	13.00	1.668	21.68	52.37	50.29
3rd Qtr 2008	118.69	13.00	1.687	21.93	48.18	48.58
Calendar 2009:						
4th Qtr 2008	$ 58.03	$ 13.00	1.636	$ 21.26	$ 11.42	$ 25.35
1st Qtr 2009	43.20	13.25	1.634	21.65	5.43	16.13
2nd Qtr 2009	59.74	13.25	1.647	21.82	11.03	26.89
3rd Qtr 2009	68.13	13.25	1.662	22.02	14.57	31.54
Calendar 2010:						
4th Qtr 2009	$ 75.90	$ 13.25	1.666	$ 22.07	$ 18.64	$ 35.19
1st Qtr 2010	78.59	14.50	1.669	24.20	18.96	35.43
2nd Qtr 2010	77.96	14.50	1.680	24.36	18.59	35.01
3rd Qtr 2010	76.04	14.50	1.681	24.37	17.43	34.23
Calendar 2011:						
4th Qtr 2010	$ 85.09	$ 14.50	1.685	$ 24.43	$ 22.70	$ 37.96
1st Qtr 2011	94.12	16.60	1.704	28.29	26.10	39.74
2nd Qtr 2011	102.58	16.60	1.740	28.88	31.48	42.21
3rd Qtr 2011	89.52	16.60	1.744	28.96	22.69	37.87
Calendar 2012:						
4th Qtr 2011	$ 93.92	$ 16.60	1.742	$ 28.92	$ 25.47	$ 39.48
1st Qtr 2012	102.86	16.70	1.753	29.28	31.29	42.29
2nd Qtr 2012	93.47	16.70	1.770	29.55	24.98	38.94
3rd Qtr 2012	92.36	16.70	1.774	29.62	23.98	38.76

(1) Production Taxes for the fourth quarter of 2007 reflect the effect of the 2006 Amendments of the Production Tax Statutes. Production Taxes for the first quarter of 2008 and subsequent periods reflect the application of ACES.

(2) Dollar amounts in the table have been rounded to two decimal places for presentation and do not reflect the precision of the actual calculations.

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THE UNITS

Units

Each Unit represents an equal undivided share of beneficial interest in the Trust. The Units do not represent an interest in or an obligation of BP Alaska, Standard Oil or any of their respective affiliates. Units are evidenced by transferable certificates issued by the Trustee. Each Unit entitles its holder to the same rights as the holder of any other Unit. The Trust has no other authorized or outstanding class of securities.

Distributions of Income

BP Alaska makes quarterly payments to the Trust of the amounts due with respect to the Trust s Royalty Interest on the fifteenth day following the end of each calendar quarter or, if the fifteenth is not a business day, on the next succeeding business day (the Quarterly Record Date). The Trustee pays all expenses of the Trust for each quarter on the Quarterly Record Date to the extent possible, then distributes the excess, if any, of the cash received by the Trust over the Trust s expenses, net of any additions to or subtractions from the cash reserve established for the payment of estimated liabilities (the Quarterly Distribution), to the persons in whose names the Units were registered at the close of business on the Quarterly Record Date.

The Trust Agreement requires the Trustee to pay the Quarterly Distribution to Unit holders on the fifth day after the Trustee s receipt of the amount paid by BP Alaska. Cash balances held by the Trustee for distribution to Unit holders are required to be invested in United States government or agency obligations secured by the full faith and credit of the United States (Government Obligations) or, if Government Obligations that mature on the date of the distribution to Unit holders are not available, in repurchase agreements secured by Government Obligations with banks having capital, surplus and undivided profits of $100,000,000 or more (which may include The Bank of New York Mellon). If time does not permit the Trustee to invest collected funds in Government Obligations or repurchase agreements, the Trustee may invest funds overnight in a time deposit with a bank meeting the foregoing capital requirement (including The Bank of New York Mellon).

Reports to Unit Holders

After the end of each calendar year, the Trustee mails a report to the persons who held Units of record during the year containing information to enable them to make the calculations necessary for federal and Alaska income tax purposes, including the calculation of any depletion or other deduction which may be available to them for the calendar year. In addition, after the end of each calendar year the Trustee mails Unit holders an annual report containing a copy of this Form 10-K and certain other information required by the Trust Agreement.

Limited Liability of Unit Holders

The Trust Agreement provides that the Unit holders are, to the full extent permitted by Delaware law, entitled to the same limitation of personal liability extended to stockholders of private corporations for profit under Delaware law.

Possible Divestiture of Units

The Trust Agreement imposes no restrictions on nationality or other status of the persons eligible to hold Units. However, it provides that if at any time the Trust or the Trustee is named a party in any judicial or administrative proceeding seeking the cancellation or forfeiture of any property in which the Trust has an interest because of the nationality, or any other status, of any one or more Unit holders, the Trustee may require each holder whose nationality or other status is an issue in the proceeding to dispose of his Units to a party not of the nationality or other status at issue in the proceeding. If any holder fails to dispose of his Units within 30 days after receipt of notice from the Trustee to do so, the Trustee will redeem any Units not so transferred within 90 days after the end of the 30-day period specified in the notice for a cash price equal to the fair market value of the Units. Units redeemed by the Trustee will be cancelled.

The Trustee may cause the Trust to borrow any amount required to redeem the Units. If the purchase of Units from an ineligible holder by the Trustee would result in a non-exempt prohibited transaction under the Employee Retirement Income Security Act of 1970, or under the Internal Revenue Code of 1986, the Units subject to the Trustee s right of redemption will be purchased by BP Alaska or a designee of BP Alaska.

Issuance of Additional Units

The Trust Agreement provides that BP Alaska or an affiliate from time to time may assign to the Trust additional royalty interests meeting certain conditions and, upon satisfaction of various other conditions, the Trust may issue up to an additional 18,600,000 Units. BP Alaska has not conveyed any additional royalty interests to the Trust, and the Trust has not issued any additional Units.

THE BP SUPPORT AGREEMENT

BP agreed to provide financial support to BP Alaska in meeting its payment obligations to the Trust in a Support Agreement dated February 28, 1989 among BP, BP Alaska, Standard Oil and the Trust (the Support Agreement). Within 30 days after BP receives notice from the Trustee that the royalty payable with respect to the Royalty Interest or any other amount payable by BP Alaska or Standard Oil has not been paid to the Trustee, BP will cause BP Alaska and Standard Oil to satisfy their respective payment obligations to the Trust and the Trustee under the Trust Agreement and the Conveyance, including contributing to BP Alaska the funds necessary to make such payments. BP is required to make available to BP Alaska and Standard Oil such financial support as BP Alaska, Standard Oil or the Trustee may request in writing. Any Unit holder has the unconditional right to institute suit against BP to enforce BP s obligations under the Support Agreement.

Neither BP nor BP Alaska may transfer or assign its rights or obligations under the Support Agreement without the prior written consent of the Trustee, except that BP can arrange for its obligations to be performed by any its affiliates so long as BP remains responsible for ensuring that its obligations are performed in a timely manner.

BP Alaska may sell or transfer all or part of its working interest in the Prudhoe Bay Unit, although such a transfer will not relieve BP of its responsibility to ensure that BP Alaska s payment obligations with respect to the Royalty Interest and under the Trust Agreement and the Conveyance are performed.

BP will be released from its obligation under the Support Agreement upon the sale or transfer of all or substantially all of BP Alaska s working interest in the Prudhoe Bay Unit if the transferee agrees in writing to assume and be bound by BP s obligation under the Support Agreement. The transferee s agreement to assume BP s obligations must be reasonably satisfactory to the Trustee and the transferee must be an entity having a rating of its unsecured, unsupported long-term debt of at least A3 from Moody s Investors Service, Inc., a rating of at least A- from Standard & Poor s, or an equivalent rating from at least one nationally-recognized statistical rating organization (after giving effect to the sale or transfer and the assumption of all of BP Alaska s obligations under the Conveyance and all of BP s obligations under the Support Agreement).

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THE PRUDHOE BAY UNIT AND FIELD

Prudhoe Bay Unit Operation and Ownership

Since several oil companies besides BP Alaska hold acreage within the Prudhoe Bay field, as well as several contiguous oil fields, the Prudhoe Bay Unit was established to optimize field development. Other owners of these fields include affiliates of Exxon Mobil Corporation, ConocoPhillips and Chevron Corporation. The Trust s Royalty Interest pertains only to production from the 1989 Working Interests in the Prudhoe Bay field and does not include production from the other oil fields included in the Prudhoe Bay Unit.

The operations of BP Alaska and the other working interest owners in the Prudhoe Bay Unit are governed by an agreement dated April 1, 1977 among the State of Alaska and the working interest owners establishing the Prudhoe Bay Unit (the Prudhoe Bay Unit Agreement) and an agreement dated April 1, 1977 among the working interest owners governing Prudhoe Bay Unit operations (the Prudhoe Bay Unit Operating Agreement).

The Prudhoe Bay Unit Operating Agreement specifies the allocation of production and costs to the working interest owners. It also defines operator responsibilities and voting requirements and is unusual in its establishment of separate participating areas for the gas cap and oil rim. Since July 1, 2000, BP Alaska has been the sole operator of the Prudhoe Bay Unit.

The ownership of the Prudhoe Bay Unit by participating area as of December 31, 2012 is shown in the following table:

	Oil rim	**Gas cap**
BP Alaska	26.36%(a)	26.36%(b)
Exxon Mobil	36.40	36.40
ConocoPhillips	36.08	36.08
Chevron	1.16	1.16
Total	100.00%	100.00%

(a) The Trust s share of oil production is computed based on BP Alaska s ownership interest in the oil rim participating area of 50.68% as of February 28, 1989. Subsequent decreases in BP Alaska s participation in oil rim ownership do not affect calculation of Royalty Production from the 1989 Working Interests and have not decreased the Trust s Royalty Interest.

(b) The Trust s share of condensate production is computed based on BP Alaska s ownership interest in the gas cap participating area of 13.84% as of February 28, 1989. Subsequent increases in BP Alaska s gas cap ownership do not affect calculation of Royalty Production from the 1989 Working Interests and have not increased the Trust s Royalty Interest.

If BP Alaska fails to pay any costs and expenses chargeable to BP Alaska under the Prudhoe Bay Unit Operating Agreement and the production of oil and condensate is insufficient to pay such costs and expenses, the Royalty Interest is chargeable with a pro rata portion of such costs and expenses and is subject to the enforcement against it of liens granted to the operators of the Prudhoe Bay Unit. However, in the Conveyance BP Alaska agreed to pay all costs and expenses chargeable to it and to ensure that no such costs and expenses will be chargeable against the Royalty Interest. The Trust is not liable for any loss or liability incurred by BP Alaska or others attributable to BP Alaska s working interest in the Prudhoe Bay Unit or to the oil produced from it and BP Alaska has agreed to indemnify the Trust and hold it harmless against any such impositions.

BP Alaska has the right to amend or terminate the Prudhoe Bay Unit Agreement, the Prudhoe Bay Unit Operating Agreement and any leases or conveyances with respect to the 1989 Working Interests in the exercise of its reasonable and prudent business judgment without liability to the Trust. BP Alaska also has the right to sell or assign all or any part of the 1989 Working Interests, so long as the sale or assignment is expressly made subject to the Royalty Interest and the terms and provisions of the Conveyance.

The Prudhoe Bay Field

The Prudhoe Bay field is located on the North Slope of Alaska, 250 miles north of the Arctic Circle and 650 miles north of Anchorage. The Prudhoe Bay field extends approximately 12 miles by 27 miles and contains nearly 150,000 gross productive acres. Approximately 45% of the acreage within the field is subject to the Royalty Interest granted to the Trust by the Conveyance. The Prudhoe Bay field, which was discovered in 1968 by BP and others, has been in production since 1977 and is the largest producing oil field in North America. As of December 31, 2012, approximately 11.43 billion barrels of oil and condensate had been produced from the Prudhoe Bay field.

Field Geology

The principal hydrocarbon accumulations at Prudhoe Bay are in the Ivishak sandstone of the Sadlerochit Group at a depth of approximately 8,700 feet below sea level. The Ivishak is overlain by four minor reservoirs of varying extent which are designated the Put River, Eileen, Sag River and Shublik (PESS) formations. Underlying the Sadlerochit Group are the oil-bearing Lisburne and Endicott formations. The net production allocated to the Royalty Interest pertains only to the Ivishak and PESS formations, collectively known as the Prudhoe Bay (Permo-Triassic) Reservoir, and does not pertain to the Lisburne and Endicott formations.

The Ivishak sandstone was deposited, commencing some 250 million years ago, during the Permian and Triassic geologic periods. The sediments in the Ivishak are composed of sandstone, conglomerate and shale which were deposited by a massive braided river and delta system that flowed from an ancient mountain system to the north. Oil was trapped in the Ivishak by a combination of structural and stratigraphic trapping mechanisms.

Gross reservoir thickness is 550 feet, with a maximum oil column thickness of 425 feet. The original oil column is bounded on the top by a gas-oil contact, originally at 8,575 feet below sea level across the main field, and on the bottom by an oil-water contact at approximately 9,000 feet below sea level. A layer of heavy oil and tar overlays the oil-water contact in the main field and has an average thickness of around 40 feet.

Oil Characteristics

The oil produced from the Prudhoe Bay (Permo-Triassic) Reservoir is a medium grade, low sulfur crude with an average specific gravity of 27 API degrees. The gas cap composition is such that, upon surfacing, a liquid hydrocarbon phase, known as condensate, is formed.

The Royalty Interest is based upon oil produced from the oil rim and condensate produced from the gas cap, but not upon gas production (which is currently uneconomic on a large scale) or natural gas liquids production stripped from gas produced.

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Historical Production

Production from the Prudhoe Bay field began on June 19, 1977, with the completion of the Trans-Alaska Pipeline System (TAPS). As of December 31, 2012 there were about 1,143 active producing oil wells, 33 gas reinjection wells, 164 water injection wells and 24 water and miscible gas injection wells in the Prudhoe Bay field. Production wells drilled in the field during the three years ended December 31, 2012 were: 56 in 2010, 38 in 2011 and 44 in 2012. No exploratory drilling activities were conducted in the field during the three-year period. Production from the Prudhoe Bay field reached a peak in 1988 and has declined steadily since then. The average well production rate was about 232 barrels per day in 2008, 243 barrels per day in 2009, 211 barrels per day in 2010, 204 barrels per day in 2011 and 197 barrels per day in 2012.

BP Alaska s share of the hydrocarbon liquids production from the Prudhoe Bay field includes oil, condensate and natural gas liquids. Using the production allocation procedures from the Prudhoe Bay Unit Operating Agreement, the Prudhoe Bay field s total production and the net share of oil and condensate (net of State of Alaska royalty) allocated to the 1989 Working Interests have been as follows during the past five years:

	Oil		Condensate	
Calendar year	Total field	Net to 1989 Working Interests	Total field	Net to 1989 Working Interests
	(thousand barrels per day)			
2008	192.7	85.4	69.4	8.4
2009	189.1	83.9	63.0	7.6
2010	183.9	81.6	59.0	7.1
2011	180.3	80.0	50.8	6.2
2012	177.8	79.7	47.8	5.8

Collection and Transportation of Prudhoe Bay Oil

Raw crude oil produced from individual production wells located at well pads is diverted to flowlines (pipelines). The flowlines transport the raw crude oil to one of six separation facilities (three on the western side of the Prudhoe Bay Unit and three on the eastern side) where the water and natural gas mixed with the raw crude are removed. The stabilized crude is then sent from the separation facilities through two 34-inch diameter transit lines, one from each half of the Prudhoe Bay Unit, to Pump Station 1, the starting point for TAPS.

At Pump Station 1, Alyeska Pipeline Service Company, the operator of TAPS, meters the oil and pumps it in the 48-inch diameter pipeline to Valdez, almost 800 miles (1,288 km) to the south, where it is either loaded onto marine tankers or stored temporarily. It currently takes the oil about 16 days to make the trip from the Prudhoe Bay Unit to Valdez, due to declining flows of oil from the North Slope. TAPS has a maximum daily average throughput of approximately 1.14 million barrels of oil; recently, however, the pipeline has been moving an average of approximately 548 thousand barrels per day.

Following a partial shutdown of the eastern side of the Prudhoe Bay Unit which lasted from August 7 until September 22, 2006, BP Alaska replaced approximately 16 miles of oil transit lines and has implemented new integrity management and corrosion monitoring practices that supplement or replace the practices that existed in 2006. BP Alaska states that its integrity management practices meet the requirements of 49 CFR 195.452 for pipeline integrity management in high consequence areas.

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Reservoir Management

The Prudhoe Bay field is a complex, combination-drive reservoir, with widely varying reservoir properties. Reservoir management involves directing field activities and projects to maximize the economic value of reserves.

Several different oil recovery mechanisms are currently active in the Prudhoe Bay field, including pressure depletion, gravity drainage/gas cap expansion, water flooding and miscible gas flooding. Separate yet integrated reservoir management strategies have been developed for the areas affected by each of these recovery processes.

Reserve Estimates

Proved oil reserves attributable to the 1989 Working Interests at December 31, 2012 are those quantities of oil which, by analysis of geoscience and engineering data, can be estimated with reasonable certainty to be economically producible from 2013 forward from known reservoirs and under existing economic conditions, operating methods and government regulations. Estimates of proved reserves are inherently imprecise and subjective and are revised over time as additional data becomes available. Such revisions often may be substantial. BP Alaska s reserve estimates and production assumptions and projections are predicated upon a reasonable estimate of the allocation of hydrocarbon liquids between oil and condensate according to the procedures of the Prudhoe Bay Unit Operating Agreement. Oil and condensate are physically produced in a commingled stream of hydrocarbon liquids. The allocation of hydrocarbon liquids between the oil and condensate from the Prudhoe Bay field is a theoretical calculation performed in accordance with procedures specified in the Prudhoe Bay Unit Operating Agreement. Under the terms of an Issues Resolution Agreement entered into by the Prudhoe Bay Unit owners in October 1990, the allocation procedures have been adjusted to generally allocate condensate in a manner which approximates the anticipated decline in the production of oil until an agreed original condensate reserve of 1,175 million barrels has been allocated to the working interest owners.

There is no precise method of forecasting the allocation of reserve volumes to the Trust. The Royalty Interest is not a working interest and the Trust is not entitled to receive any specific volume of reserves from the 1989 Working Interests. The reserve volumes attributable to the 1989 Working Interests are estimated using an allocation of reserve volumes based on estimated future production and the average WTI Price, and assume no future movement in the Consumer Price Index and no changes to the procedure for calculating Production Taxes. The estimated reserve volumes attributable to the Trust will vary if different estimates of production, prices and other factors are used. Even if expected reservoir performance does not change, the estimated reserves, economic life, and future revenues attributable to the Trust may change significantly in the future. This may result from changes in the WTI Price or from changes in other prescribed variables utilized in calculations defined by the Overriding Royalty Conveyance.

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The reserves attributable to the 1989 Working Interests constitute only a part of the overall reserves in the Prudhoe Bay Unit. BP Alaska has estimated that the net remaining proved reserves allocated to the Trust as of December 31, 2012 were 75.517 million barrels of oil and condensate, of which 70.676 million barrels are proved developed reserves[2] and 4.841 million barrels are proved undeveloped reserves[3]. Approximately 2.19 million barrels (net) of proved undeveloped reserves allocated to the Trust were converted into proved developed reserves during 2012. Approximately 0.16 million barrels (net) of proved undeveloped reserves allocated to the Trust were added during 2012 as a result of planned projects. Approximately 1.96 million barrels (net) of proved undeveloped reserves allocated to the Trust were reclassified as non-proved during 2012 as a result of rephasing of BP s business plan. There were no contributions to proved undeveloped reserves from extensions or discoveries during 2012. To the extent that the estimated volumes of proved undeveloped reserves include reserves the development of which is scheduled to commence after five years, the inclusions are based on a development plan which calls for drilling wells over an extended period of time given the magnitude of the development. BP has a historical record of completing comparable projects. Based on the 2012 twelve-month average WTI Price[4] of $94.71 per barrel, other economic parameters prescribed by the Conveyance, and utilizing procedures specified in Financial Accounting Standards Board Accounting Standards Codification (FASB ASC) 932, *Extractive Activities Oil and Gas*, BP Alaska calculated that as of December 31, 2012 production of oil and condensate from the proved reserves allocated to the 1989 Working Interests will result in estimated future net revenues to the Trust of $2,176.0 million, with a present value of $1,314.9 million.

The internal controls applicable to the foregoing estimates of the reserves allocated to the Trust are those employed by BP, which provides the information to the Trustee. BP Alaska has advised the Trustee that BP s vice president of segment reserves is the petroleum engineer primarily responsible for overseeing the preparation of the reserves estimate. He has 30 years of diversified industry experience managing the governance and compliance of BP s reserves estimation since 2005. He is a past member of the Society of Petroleum Engineers Oil and Gas Reserves Committee, a sitting member of the American Association of Petroleum Geologists Committee on Resource Evaluation and current chair of the bureau of the United Nations Economic Commission for Europe Expert Group on Resource Classification. The Trust employs Miller and Lents, Ltd., an international oil and gas consulting firm, to conduct an annual review of BP Alaska s estimates of the proved reserves allocated to the Trust, estimated future net revenues to the Trust, and the remaining period of economic production from the Prudhoe Bay field. The engineering staff members assigned to the Trust project are all university graduates, with degrees in petroleum engineering and/or advanced degrees in petroleum or chemical engineering. All are licensed professional engineers with over 25 years of diversified experience, including at least 10 years of experience with the Trust. A copy of the February 15, 2013 report of Miller and Lents, Ltd. is filed as Exhibit 99 to this report.

BP Alaska has undertaken a program of field-wide infrastructure renewal, pipeline replacement, and mechanical improvements to wells. As a consequence of these activities and their required downtime, and the natural production declines discussed above under Historical Production, BP Alaska s net production of oil and condensate allocated to the Trust from proved reserves was less than 90,000 barrels per day on an annual basis in 2010, 2011 and 2012. BP Alaska anticipates that its average net production of oil and condensate allocated to the Trust from proved reserves will be below 90,000 barrels per day on an annual average basis most future years. The occurrence of major gas sales could accelerate the decline in net production, due to the consequent decline in reservoir pressure. See Item 1A, RISK FACTORS. Based on the 2012 twelve-month average WTI Price of $94.71 per barrel, current Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, it is estimated that

[2] Proved developed reserves are reserves that can be expected to be recovered through existing wells with existing equipment and operating methods or in which the cost of the required equipment is relatively minor compared to the cost of a new well.

[3] Proved undeveloped reserves are reserves that are expected to be recovered from new wells on undrilled acreage, or from existing wells where a relatively major expenditure is required for recompletion.

[4] The unweighted arithmetic average of the WTI Price on the first day of each month during the year.

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royalty payments to the Trust will continue through the year 2029. BP Alaska expects continued economic production from the Prudhoe Bay field at a declining rate after that year; however, for the economic conditions and production forecast as of December 31, 2012 the Per Barrel Royalty will be zero following the year 2029.

BP Alaska is under no obligation to make investments in development projects which would add additional non-proved resources to proved reserves and cannot make such investments without the concurrence of the Prudhoe Bay Unit working interest owners. The Prudhoe Bay Unit working interest owners regularly assess the technical and economic attractiveness of implementing projects to increase Prudhoe Bay Unit proved reserves. See Item 1A, RISK FACTORS, below.

In the event of changes in BP Alaska s current assumptions, oil and condensate recoveries may be reduced from the current estimates, unless recovery projects other than those included in the current estimates are implemented.

INDUSTRY CONDITIONS AND REGULATIONS

The production of oil and gas in Alaska is affected by many state and federal regulations with respect to allowable rates of production, marketing, environmental matters and pricing. Future regulations could change allowable rates of production or the manner in which oil and gas operations may be lawfully conducted.

In general, BP Alaska s oil and gas activities are subject to existing federal, state and local laws and regulations relating to health, safety, environmental quality and pollution control. BP Alaska believes that the equipment and facilities currently being used in its operations generally comply with the applicable legislation and regulations. During the past few years, numerous environmental laws and regulations have taken effect at the federal, state and local levels. Oil and gas operations are subject to extensive federal and state regulation and to interruption or termination by governmental authorities due to ecological and other considerations and in certain circumstances impose absolute liability upon lessees for the cost of cleaning up pollutants and for pollution damages resulting from their operations. Although BP Alaska has advised that the existence of legislation and regulation has had no material adverse effect on BP Alaska s current method of operations, the effect of future legislation and regulations cannot be predicted.

Since the end of 2006, the corrosion monitoring and mitigation practices for the oil transit lines in the Prudhoe Bay Unit have been monitored and reviewed by the U.S. Department of Transportation. The construction, testing, and commissioning of the new replacement oil transit lines have been inspected by DOT inspectors. The replacement lines have been constructed and are operated and maintained in accordance with the requirements of the Pipeline Inspection, Protection, Enforcement and Safety Act of 2006 (the PIPES Act). The applicable requirements of the subsequent regulations of the PIPES Act began to be phased in 2012. See THE PRUDHOE BAY UNIT AND FIELD Collection and Transportation of Prudhoe Bay Oil above.

CERTAIN TAX CONSIDERATIONS

The following is a summary of the principal tax consequences to Unit holders resulting from the ownership and disposition of Units. The laws and regulations affecting these matters are complex, and are subject to change by future legislation or regulations or new interpretations by the Internal Revenue Service, state taxing authorities or the courts. In addition, there may be differences of opinion as to the applicability or interpretation of present tax laws and regulations. BP Alaska and the Trust have not requested any rulings from the Internal Revenue Service with respect to the tax treatment of the Units, and no assurance can be given that the Internal Revenue Service would concur with the statements below.

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Unit holders are urged to consult their tax advisors regarding the effects on their specific tax situations of owning and disposing of Units.

Federal Income Tax

Classification of the Trust

The following discussion assumes that the Trust is properly classified as a grantor trust under current law and is not an association taxable as a corporation.

General Features of Grantor Trust Taxation

A grantor trust is not subject to tax, and its beneficiaries (the Unit holders in the case of the Trust) are considered for tax purposes to own the assets of the trust directly. The Trust pays no federal income tax but files an information return reporting all items of income or deduction. If a court were to hold that the Trust is an association taxable as a corporation, the Trust would incur substantial income tax liabilities in addition to its other expenses.

Taxation of Unit Holders

In computing his federal income tax liability, each Unit holder is required to take into account his share of all items of Trust income, gain, loss, deduction, credit and tax preference, based on the Unit holder s method of accounting. Consequently, it is possible that in any year a Unit holder s share of the taxable income of the Trust may exceed the cash actually distributed to him in that year. For example, if the Trustee should add to the reserve for the payment of Trust liabilities or repay money borrowed to satisfy debts of the Trust, the money used to replenish the reserve or to repay the loan is income to and must be reported by the Unit holder, even though the money was not distributed to the Unit holder.

The Trust makes quarterly distributions to the persons who held Units of record on each Quarterly Record Date. The terms of the Trust Agreement seek to assure to the extent practicable that income, expenses and deductions attributable to each distribution are reportable by the Unit holder who receives the distribution.

The Trust allocates income and deductions to Unit holders based on record ownership at Quarterly Record Dates. It is not known whether the Internal Revenue Service will accept the allocation based on this method.

Depletion Deductions

The owner of an economic interest in producing oil and gas properties is entitled to deduct an allowance for the greater of cost depletion or (if otherwise allowable) percentage depletion on each such property. A Unit holder s deduction for cost depletion in any year is calculated by multiplying the holder s adjusted tax basis in his Units (generally his cost less prior depletion deductions) by Royalty Production during the year and dividing that product by the sum of Royalty Production during the year and estimated remaining Royalty Production as of the end of the year. The allowance for percentage depletion generally does not apply to interests in proven oil and gas properties that were transferred after December 31, 1974 and prior to October 12, 1990. The Omnibus Budget Reconciliation Act of 1990 repealed this rule for transfers occurring on or after October 12, 1990. Unit holders who acquired their Units on or after that date may be permitted to deduct an allowance for percentage depletion if such deduction would otherwise exceed the allowable deduction for cost depletion. In order to take percentage depletion, a Unit holder must qualify for the independent producer exemption contained in section

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613A(c) of the Internal Revenue Code of 1986. Percentage depletion is based on the Unit holder s gross income from the Trust rather than on his adjusted basis in his Units. Any deduction for cost depletion or percentage depletion allowable to a Unit holder reduces his adjusted basis in his Units for purposes of computing subsequent depletion or gain or loss on any subsequent disposition of Units.

Unit holders must maintain records of their adjusted basis in their Units, make adjustments for depletion deductions to such basis, and use the adjusted basis for the computation of gain or loss on the disposition of the Units.

Taxation of Foreign Unit Holders

Generally, a holder of Units who is a nonresident alien individual or which is a foreign corporation (a Foreign Taxpayer) is subject to tax on the gross income produced by the Royalty Interest at a rate equal to 30% (or at a lower treaty rate, if applicable). This tax is withheld by the Trustee and remitted directly to the United States Treasury. A Foreign Taxpayer may elect to treat the income from the Royalty Interest as effectively connected with the conduct of a United States trade or business under Internal Revenue Code section 871 or section 882, or pursuant to any similar provisions of applicable treaties. If a Foreign Taxpayer makes this election, it is entitled to claim all deductions with respect to such income, but a United States federal income tax return must be filed to claim such deductions. This election once made is irrevocable unless an applicable treaty provides otherwise or unless the Secretary of the Treasury consents to a revocation.

Section 897 of the Internal Revenue Code and the Treasury Regulations thereunder treat the Trust as if it were a United States real property holding corporation. Foreign holders owning more than five percent of the outstanding Units are subject to United States federal income tax on the gain on the disposition of their Units. Foreign Unit holders owning less than five percent of the outstanding Units are not subject to United States federal income tax on the gain on the disposition of their Units, unless they have elected under Internal Revenue Code section 871 or section 882 to treat the income from the Royalty Interest as effectively connected with the conduct of a United States trade or business.

If a Foreign Taxpayer is a corporation which made an election under Internal Revenue Code section 882(d), the corporation would also be subject to a 30% tax under Internal Revenue Code section 884. This tax is imposed on U.S. branch profits of a foreign corporation that are not reinvested in the U.S. trade or business. This tax is in addition to the tax on effectively connected income. The branch profits tax may be either reduced or eliminated by treaty.

Sale of Units

Generally, a Unit holder will realize gain or loss on the sale or exchange of his Units measured by the difference between the amount realized on the sale or exchange and his adjusted basis for such Units. Gain on the sale of Units by a holder that is not a dealer with respect to such Units will generally be treated as capital gain. However, pursuant to Internal Revenue Code section 1254, certain depletion deductions claimed with respect to the Units must be recaptured as ordinary income upon sale or disposition of such interest.

Backup Withholding

A payor must withhold 28% of any reportable payment if the payee fails to furnish his taxpayer identification number (TIN) to the payor in the required manner or if the Secretary of the Treasury notifies the payor that the TIN furnished by the payee is incorrect. Unit holders will avoid backup withholding by furnishing their correct TINs to the Trustee in the form required by law.

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Widely Held Fixed Investment Trusts

The Trustee assumes that some Trust Units are held by a middleman, as such term is broadly defined in the U.S. Treasury Regulations (which includes custodians, nominees, certain joint owners, and brokers holding an interest for a custodian in street name). Therefore, the Trustee considers the Trust to be a widely held fixed investment trust (WHFIT) for U.S. Federal income tax purposes. The Bank of New York Mellon Trust Company, N.A. is the representative of the Trust that will provide tax information in accordance with applicable U.S. Treasury Regulations governing the information reporting requirements of the Trust as a WHFIT. For information contact The Bank of New York Mellon Trust Company, N.A., Global Corporate Trust Corporate Finance, 919 Congress Avenue, Suite 500, Austin, TX 78701, telephone number (512) 236-6565.

State Income Taxes

Unit holders may be required to report their share of income from the Trust to their state of residence or commercial domicile. However, only corporate Unit holders will need to report their share of income to the State of Alaska. Alaska does not impose an income tax on individuals or estates and trusts. All Trust income is Alaska source income to corporate Unit holders and should be reported accordingly.

ITEM 1A. RISK FACTORS

Owners of Units are exposed to risks and uncertainties that are particular to their investment.

Royalty Production from the Prudhoe Bay field is projected to decline and will eventually cease.

The Prudhoe Bay field has been in production since 1977. Development of the field is largely completed and proved reserves are being depleted. Production of oil and condensate from the field has been declining during recent years and the decline is expected to continue. Royalty payments to the Trust are projected to cease after 2029. Production estimates included in this report are based on economic conditions and production forecasts as of the end of 2012, and also depend on various assumptions, projections and estimates which are continually revised and updated by BP Alaska. These revisions could result in material changes to the projected declines in production. It is possible that economic production from the reserves allocated to the 1989 Working Interests could decline more quickly and end sooner than is currently projected, especially if construction of a gas pipeline makes it economical to produce natural gas from the Prudhoe Bay field on a large scale, as discussed below.

Construction of a gas pipeline from the North Slope of Alaska could accelerate the decline in Royalty Production from the Prudhoe Bay field.

The construction of a natural gas pipeline to bring natural gas from the North Slope could make it economical to extract natural gas from the Prudhoe Bay field and transport it to market. Currently, natural gas released by pumping oil is reinjected into the ground, which helps to maintain reservoir pressure and facilitates extraction of oil from the field. Extraction of natural gas from the Prudhoe Bay field would lower reservoir pressure, although carbon dioxide stripped out of the gas could be reinjected and other methods could be employed to mitigate the reduction. The lowering of the reservoir pressure could accelerate the decline in production from the 1989 Working Interests and the time at which royalty payments to the Trust would cease. Since the Trust is not entitled to any royalty payments with respect to natural gas production from the 1989 Working Interests, the Unit holders would not realize any offsetting benefit from natural gas production from the Prudhoe Bay field.

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Without a pipeline, extraction of natural gas from the Prudhoe Bay field on a large scale would not be economical. Two subsidiaries of Calgary-based TransCanada Corporation (TransCanada) have been issued a license by the state of Alaska under the Alaska Gasline Inducement Act (AGIA) to construct a large-diameter natural gas pipeline from the North Slope. Under the license, the state will provide up to $500 million in matching funds and other incentives in exchange for TransCanada doing its best to secure customers for the pipeline, financing, and regulatory clearances from the Federal Energy Regulatory Commission (FERC) and Canadian authorities. TransCanada and affiliates of ExxonMobil have combined to promote a joint venture named the Alaska Pipeline Project. The Alaska Pipeline Project originally contemplated a large-diameter pipeline extending from the North Slope through Alaska, and then into Canada through the Yukon Territory and British Columbia to the existing Alberta Storage Hub. The Alaska Pipeline Project proposal also included an alternative pipeline route that would extend from the North Slope to a third-party liquefied natural gas terminal near Valdez, Alaska.

In May 2012, TransCanada terminated its open season to transport North Slope gas through its Alaska Pipeline Project due to unsuccessful efforts to secure transportation agreements. TransCanada also notified FERC in May 2012 that it was curtailing interim work on the Alberta pipeline option, but that it was working with other North Slope producers to explore the feasibility of developing a liquefied natural gas export terminal at an undetermined location in South Central Alaska. TransCanada estimated that it would file an application with FERC for that project in October 2014. FERC has stopped work on an environmental impact statement for the Alberta pipeline project.

In October 2012, ExxonMobil, ConocoPhillips, BP and TransCanada notified Alaska Governor Sean Parnell that they had agreed on a plan to combine what were once two competing natural-gas pipeline projects destined for the continental U.S. into one project focused on export markets. The project contemplates building an 800-mile natural-gas pipeline from the North Slope to a port on the southern coast of Alaska from which liquefied natural gas would be exported to Asia. The new project would also include natural-gas processing facilities and a natural-gas export terminal. The announcement by the consortium followed a March 2012 settlement between the state of Alaska and the companies over a dispute relating to leases at the Point Thomson field, located east of the Prudhoe Bay field. The companies were allowed to keep their large leases in exchange for promises to begin first oil production from Point Thomson by 2016 and to combine their competing projects.

It is expected that the export project could take a decade or more to complete due to the scale of construction and the number and complexity of technical, legal, political and financial issues involved. The consortium also anticipates that the cost of the project, estimated to be $45 billion, could actually exceed $65 billion. However, upon completion, the companies expect that they would be able to transport billions of dollars in natural gas that is now stranded on the North Slope.

It is expected that Alaskan natural gas would encounter substantial competition for customers in Asian markets, since several large liquefied natural gas projects are expected to come online in Australia in the next few years to meet Asian energy demand. There is also a more developed project to export liquefied natural gas from British Columbia, where gas production costs may be lower.

Royalty Production from the Prudhoe Bay field may have been adversely affected by the recent changes to the Alaska Production Tax Statutes.

The 2007 adoption of ACES (see THE ROYALTY INTEREST Production Taxes in Item 1 above) may have accelerated the decline in production of oil and condensate from the Prudhoe Bay field to the extent that it has caused BP Alaska and the other owners of working interests in the Prudhoe Bay

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Unit to reduce or defer investment in oil production infrastructure renewal, well development and implementation of new technology due to uncompetitive returns on investment in Alaska. ACES, in addition to increasing the basic oil production tax rate and the progressivity factor, also eliminates or reduces many deductions and credits permitted under the 2006 Amendments. Since 2007, BP Alaska s spending on production adding activity, adjusted for inflation, has been flat to declining.

Royalty payments by BP Alaska to the Trust are unpredictable, because they depend on Cushing, Oklahoma WTI spot prices, which have been volatile in recent years, and on the volume of production from the 1989 Working Interests, which may vary from quarter to quarter in the future.

Even though WTI Prices have been rising generally in recent years, they nevertheless remain subject to significant periodic fluctuations. These fluctuations were especially pronounced during 2008 and 2009. In 2012 the WTI average price of about $95 per barrel was down from the 2011 average price of about $96 per barrel. The general trend of WTI price increases has moderated more recently as a result of increasing volumes of crude oil production from Canada and the Bakken shale formation, situated in the northwest portion of North Dakota (and extending into Montana and portions of Canada), moving into the U.S. Midwest market where most WTI is refined. With these new oil flows from Canada and the United States, Cushing, Oklahoma, the delivery point for WTI futures contracts on the New York Mercantile Exchange, has become oversupplied, keeping the price of WTI crude oil for much of the year at a historic discount to globally traded waterborne crudes such as Brent. In the past, WTI was more likely to trade at a premium to Brent. The discount reached a record of $29.70 per barrel on September 22, 2011, ending with an annual level of $16.38. In 2012, the annual average price gap between Brent and WTI surpassed that of 2011, finishing with an annual level of $17.61 per barrel.

In December 2012, the U.S. Energy Information Administration (EIA) used North Sea Brent instead of WTI for its price forecasts in its Annual Energy Outlook (AEO) 2013. This is the first time that Brent has been used in the AEO, an acknowledgment of the growing discrepancy between WTI and global crude prices and of the view that Brent is a better reflection of global oil demand and supply than WTI.

As noted above, it is generally considered that the WTI spot price has been weighed down due in part to constraints on transportation of crude oil out of the U.S. Midwest market. That market has been reliant on high-cost rail and trucks to ship both crude oil stored at Cushing and production from Canada and the Bakken shale formation to the Gulf Coast. However, in November 2011, ConocoPhillips announced it was selling its 50% share of the Seaway crude oil pipeline, which links markets in the Houston area with oil storage facilities near Cushing, to Enbridge, Inc. Enbridge and Enterprise Products Partners, the other joint owner of Seaway, subsequently announced that Seaway intended to reverse oil flows to run north to south. Historically, pipelines have flowed from the Gulf Coast to Cushing. In May 2012, Enbridge and Enterprise completed a project to reverse the flow direction of the Seaway Pipeline.

The reversed Seaway Pipeline was initially able to transport up to 150,000 barrels per day of crude oil from Cushing to the Gulf Coast. The ability to ship crude oil out of Cushing via pipeline, while not eliminating delays in moving WTI crude oil to other markets, was expected to allow WTI and similar inland U.S. crudes to compete directly with the higher-priced waterborne crude oils on the Gulf Coast (whose prices have historically closely followed Brent). As a result, it was anticipated that the price of WTI could be brought more in line with prices for other crude oils trading on the global markets.

Following pump station additions and modifications, the Seaway Pipeline capacity was increased to 400,000 barrels per day on January 11, 2013 to further relieve the glut of crude oil at Cushing. However, Enterpise has since announced that the Seaway Pipeline will have limitations in its delivery rates until a new pipeline lateral is finished in late 2013.

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It is also expected that by 2014, other pipeline projects from the Mid-continent to Gulf Coast refining centers will come on line, reducing the cost of transporting crude oil to refiners. For example, a new extension of the Keystone pipeline network, called the Keystone XL pipeline, would expand the reach of the network by adding a segment from Cushing to the Gulf Coast of Texas. In this segment, domestic oil would be added to the pipeline at Cushing and would then extend 485 miles to a delivery point near terminals in Nederland, Texas to serve the Port Arthur, Texas marketplace. An approximately 47 mile-long existing pipeline is also proposed to be used to transport crude oil from the pipeline in Liberty County, Texas to the Houston, Texas area. Construction on the Gulf Coast project commenced in August, 2012, with an anticipated in service date of late 2013. It is expected that the Gulf Coast project will have the initial capacity to transport 700,000 barrels of oil per day and that it can be expanded to transport 830,000 barrels of oil per day to Gulf Coast refineries.

In anticipation of the new pipeline take-away capacity from Cushing, new pipeline capacity to deliver 1,190,000 barrels per day of crude oil from Canada and the midcontinent into the Cushing hub is also planned during the next two years. However, it is considered that the planned pipeline capacity additions to deliver crude oil from Cushing to the Gulf Coast, together with the planned new pipeline capacity to move crude oil directly from the Permian Basin to the Gulf Coast, could result in a significant drop in waterborne imports, particularly of light sweet crude oil, to the U.S. Gulf Coast.

While energy price forecasts are highly uncertain, EIA projects that the Brent crude oil spot price will fall from an average of $112 per barrel in 2012 to annual averages of $105 per barrel and $99 per barrel in 2013 and 2014, respectively, reflecting the increasing supply of liquid fuels by non-OPEC countries. EIA forecasts that the WTI price will average $90 per barrel in 2013 before increasing to an average of $91 per barrel in 2014.

Oil production in the United States has also increased at the fastest rate in almost two decades owing, in part, to a dramatic increase in horizontal drilling and hydraulic fracturing, or fracking, and other technological advances in oil detection and extraction. This increase, according the International Energy Agency s November 2012 World Energy Outlook, has put the U.S. on a course to become the world s top producer of oil by 2020, a net exporter of oil around 2030 and nearly self-sufficient in energy by 2035.

However, future domestic and international events and conditions may produce wide swings in crude oil prices over relatively short periods of time. Recent moves in crude oil prices have been affected by many factors. These include changes in demand by oil-consuming countries, the actions of OPEC to control production by members of the cartel, shifts in inventory management strategies by international oil companies, conservation measures by consumers, increasing effects of the oil futures market and other unpredictable political, psychological and economic factors, such as, most recently, the global economic recession, political turmoil in North Africa and the Middle East and ongoing tensions in the Persian Gulf over Iran s nuclear program.

For additional information, see the history of WTI Prices since 1986 published by the U.S. Energy Information Administration at http://tonto.eia.doe.gov.

It is increasingly likely that the Trust s revenues in future periods also will be affected by decreases in production from the 1989 Working Interests. BP Alaska s average net production of oil and condensate allocated to the Trust from proved reserves was less than 90,000 barrels per day on an annual basis during 2010, 2011 and 2012, and the Trustee has been advised that BP Alaska expects that average net production allocated to the Trust from the proved reserves will be less than 90,000 barrels a day on an annual basis in future years. Unit holders thus are subject to the risk that cash distributions with respect to their Units may vary widely from quarter to quarter.

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Prudhoe Bay field oil production could be shut in partially or entirely from time to time as a result of damage to or failures of field pipelines or equipment.

In August 2006, BP Alaska shut down the eastern side of the Prudhoe Bay Unit following the discovery of unexpectedly severe corrosion and a small spill from the oil transit line on that side of the Unit. Earlier, in March of 2006, BP had to temporarily shut down and commence the replacement of a three-mile segment of transit line on the western side of the Prudhoe Bay Unit following discovery of a large oil spill.

BP Alaska completely replaced approximately 16 miles of transit lines on the eastern and western sides of the Prudhoe Bay Unit and has implemented federally-required corrosion monitoring practices. However, the discovery of additional defects in Prudhoe Bay Unit oil flowlines and transit lines, and damage to or failures of separation facilities or other critical equipment, could result in future shutdowns of oil production from all or portions of the Prudhoe Bay Unit and have an adverse effect on future royalty payments.

Oil production from the Prudhoe Bay Unit could be interrupted by damage to the Trans-Alaska Pipeline System from natural causes, accidents, deliberate attacks or declining oil flows.

The Trans-Alaska Pipeline System connects the North Slope oil fields to the southern port of Valdez, almost 800 miles away. It is the only way that oil can be transported from the North Slope to market. The pipeline system crosses three mountain ranges, many rivers and streams and thaw-sensitive permafrost. It is susceptible along its length to damage from earthquakes, forest fires and other natural disasters. The pipeline system also is vulnerable to failures of pipeline segments and pumping equipment, accidental damage and deliberate attacks. Recently, the pipeline has become susceptible to damage resulting from declining flows of oil from the North Slope. Slower flows cause the temperature of the oil in the pipeline to cool faster, increasing the rate of deposit of wax, which coats pipe walls, hides corrosion and clogs sensors on smart pigs sent through the pipeline to detect it. Even lower flow rates projected in the future may lead to internal damage caused by ice formation within the pipe and external damage from frost heaves under buried segments. Major upgrades to the pipeline may be required to counteract the effects of cooler oil temperature. If the pipeline or its pumping stations should suffer major damage from natural or man-made causes, production from the Prudhoe Bay Unit could be shut in until the pipeline system can be repaired and restarted. Royalty payments to the Trust could be halted or reduced by a material amount as a result of interruption to production from the Prudhoe Bay Unit.

In January 2011, TAPS was shut down over two periods of several days each as a result of the discovery of a leak of crude oil in the basement of a booster pump building at Pump Station No. 1. See THE PRUDHOE BAY UNIT AND FIELD Collection and Transportation of Prudhoe Bay Oil in Item 1 for additional information

Production from the 1989 Working Interests may be interrupted or discontinued by BP Alaska.

BP Alaska has no obligation to continue production from the 1989 Working Interests or to maintain production at any level and may interrupt or discontinue production at any time. The Trust does not have the right to take over operation of the 1989 Working Interests or share in any operating decisions by BP Alaska concerning the Prudhoe Bay Unit. The operation of the Prudhoe Bay Unit is subject to normal operating hazards incident to the production and transportation of oil in Alaska. In the event of damage to the infrastructure, facilities and equipment in the Prudhoe Bay field which is covered by insurance, BP Alaska has no obligation to use insurance proceeds to repair such damage and may elect to retain such proceeds and close damaged areas to production.

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There are potential conflicts of interest between BP Alaska and the Trust that could affect the royalties paid to Unit holders. The interests of BP Alaska and the Trust with respect to the Prudhoe Bay Unit could at times be different. The Per Barrel Royalty that BP Alaska pays to the Trust is based on the WTI Price, Chargeable Costs and Production Taxes, all of which are amounts contractually defined in the Conveyance. The WTI Price does not necessarily correspond to the actual price realized by BP Alaska for crude oil produced from the 1989 Working Interests, and Chargeable Costs and Production Taxes may not bear any relation to BP Alaska s actual costs of production and tax expenses. The actual per barrel profit realized by BP Alaska on the Royalty Production may differ materially from the Per Barrel Royalty that it is required to pay to the Trust. It is possible under certain circumstances that the relationship between BP Alaska s actual per barrel revenues and costs could be such that BP Alaska might determine to interrupt or discontinue production in whole or in part from the 1989 Working Interests even though a Per Barrel Royalty might otherwise be payable to the Trust under the Conveyance.

ITEM 1B. UNRESOLVED STAFF COMMENTS

The Trust has not received any written comments from the staff of the Securities and Exchange Commission regarding its periodic or current reports under the Securities Exchange Act of 1934 (the Exchange Act) that remain unresolved.

ITEM 2. PROPERTIES

Reference is made to Item 1 for the information required by this item.

ITEM 3. LEGAL PROCEEDINGS

None

ITEM 4. MINE SAFETY DISCLOSURE

Not applicable.

PART II

ITEM 5. MARKET FOR REGISTRANT S UNITS, RELATED UNITHOLDER MATTERS AND ISSUER PURCHASES OF UNITS

The Units are listed and traded on the New York Stock Exchange under the symbol BPT. The following table shows the high and low sales prices per Unit on the New York Stock Exchange and the cash distributions paid per Unit, for each calendar quarter in the two years ended December 31, 2012.

	High	Low	Distributions Per Unit
2011:			
First Quarter	$ 131.49	$ 100.76	$ 2.408
Second Quarter	124.49	103.30	2.393
Third Quarter	117.72	100.51	2.639
Fourth Quarter	116.39	96.18	1.956

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	High	Low	Distributions Per Unit
2012:			
First Quarter	$ 127.00	$ 112.77	$ 2.516
Second Quarter	129.49	104.04	2.643
Third Quarter	122.00	75.12	2.313
Fourth Quarter	94.43	65.56	1.822

As of February 24, 2013, 21,400,000 Units were outstanding and were held by 465 holders of record. No Units were purchased by the Trust or any affiliated purchaser during the year ended December 31, 2012.

Future payments of cash distributions are dependent on such factors as prevailing WTI Prices, the relationship of the rate of change in the WTI Price to the rate of change in the Consumer Price Index, the Chargeable Costs, the rates of Production Taxes prevailing from time to time, and the actual Royalty Production from the 1989 Working Interests. See THE ROYALTY INTEREST in Item 1.

ITEM 6. SELECTED FINANCIAL DATA

The following table presents in summary form selected financial information regarding the Trust.

		Year ended December 31 (in thousands, except per Unit amounts)				
		2012	2011	2010	2009	2008
Royalty revenues	$	200,019	202,325	184,042	130,014	252,298
Litigation expense reimbursement	$			1,705		
Settlement revenue	$				29,474	
Interest income	$	1	1	2	4	33
Trust administration expenses	$	(1,152)	(1,217)	(1,338)	(1,459)	(1,797)
Cash earnings	$	198,868	201,109	184,411	158,033	250,534
Cash distributions	$	198,885	201,092	213,885	128,575	250,525
Cash distributions per unit	$	9.294	9.397	9.995	6.008	11.707

		December 31 (dollar amounts in thousands)				
		2012	2011	2010	2009	2008
Trust corpus	$	826	890	862	32,273	4,757
Total assets	$	1,001	1,018	1,001	32,484	5.035
Units outstanding		21,400,000	21,400,000	21,400,000	21,400,000	21,400,000

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ITEM 7. TRUSTEE S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

Liquidity and Capital Resources

The Trust is a passive entity. The Trustee s activities are limited to collecting and distributing the revenues from the Royalty Interest and paying liabilities and expenses of the Trust. Generally, the Trust has no source of liquidity and no capital resources other than the revenue attributable to the Royalty Interest that it receives from time to time. See the discussion under THE ROYALTY INTEREST in Item 1 for a description of the calculation of the Per Barrel Royalty, and the discussion under THE PRUDHOE BAY UNIT AND FIELD Reserve Estimates in Item 1 for information concerning the estimated future net revenues of the Trust. However, the Trust Agreement gives the Trustee power to borrow, establish a cash reserve, or dispose of all or part of the Trust property under limited circumstances. See the discussion under THE TRUST Sales of Royalty Interest; Borrowings and Reserves in Item 1.

Since 1999, the Trustee has maintained a $1,000,000 cash reserve to provide liquidity to the Trust during any future periods in which the Trust does not receive a distribution. The Trustee will draw funds from the cash reserve account during any quarter in which the quarterly distribution received by the Trust does not exceed the liabilities and expenses of the Trust, and will replenish the reserve from future quarterly distributions, if any. The Trustee anticipates that it will keep this cash reserve program in place until termination of the Trust.

Amounts set aside for the cash reserve are invested by the Trustee in U.S. government or agency securities secured by the full faith and credit of the United States. Interest income received by the Trust from the investment of the reserve fund is added to the distributions received from BP Alaska and paid to the Unit holders on each Quarterly Record Date.

Annual decreases in Trust corpus and total assets are the result of amortization of the Royalty Interest. See Notes 2 and 3 of Notes to Financial Statements in Item 8.

Results of Operations

Relatively modest changes in oil prices significantly affect the Trust s revenues and results of operations. Crude oil prices are subject to significant changes in response to fluctuations in the domestic and world supply and demand and other market conditions as well as the world political situation as it affects OPEC and other producing countries. The effect of changing economic conditions on the demand and supply for energy throughout the world and future prices of oil cannot be accurately projected.

Royalty revenues are generally received on the Quarterly Record Date (generally the fifteenth day of the month) following the end of the calendar quarter in which the related Royalty Production occurred. The Trustee, to the extent possible, pays all expenses of the Trust for each quarter on the Quarterly Record Date on which the revenues for the quarter are received. For the statement of cash earnings and distributions, revenues and Trust expenses are recorded on a cash basis and, as a result, distributions to Unit holders in each calendar year ending December 31 are attributable to BP Alaska s operations during the twelve-month period ended on the preceding September 30.

When BP Alaska s average net production of oil and condensate per quarter from the 1989 Working Interests exceeds 90,000 barrels a day, the principal factors affecting the Trust s revenues and distributions to Unit holders are changes in WTI Prices, scheduled annual increases in Chargeable Costs, changes in the Consumer Price Index and changes in Production Taxes. However, it is likely that the

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Trust s revenues in future periods also will be affected by increases and decreases in production from the 1989 Working Interests. BP Alaska s net production of oil and condensate allocated to the Trust from proved reserves was less than 90,000 barrels per day on an annual basis during 2010, 2011 and 2012. The Trustee has been advised that BP Alaska expects that average net production allocated to the Trust from the proved reserves will be less than 90,000 barrels a day on an annual basis in future years.

BP Alaska estimates Royalty Production from the 1989 Working Interests for purposes of calculating quarterly royalty payments to the Trust because complete actual field production data for the preceding calendar quarter generally is not available by the Quarterly Record Date. To the extent that average net production from the 1989 Working Interests is below 90,000 barrels per day, calculation by BP Alaska of actual Royalty Production data may result in revisions of prior Royalty Production estimates. Revisions by BP Alaska of its Royalty Production calculations may result in quarterly royalty payments by BP Alaska which reflect adjustments for overpayments or underpayments of royalties with respect to prior quarters. Such adjustments, if material, may adversely affect certain Unit holders who buy or sell Units between the Quarterly Record Dates for the Quarterly Distributions affected. See Note 8 of Notes to Financial Statements in Item 8. Because the annual statement of cash earnings and distributions of the Trust is prepared on a modified cash basis, royalty revenues for the calendar year do not include the amounts of underpayments or overpayments affecting payments received during the fourth quarter of the year.

During the years 2011 and 2012 and the period of 2013 up to the date of this report, WTI Prices have been above the level necessary for the Trust to receive a Per Barrel Royalty. Whether the Trust will be entitled to future distributions during the remainder of 2013 will depend on WTI Prices prevailing during the remainder of the year.

2012 compared to 2011

As explained in Note 2 of Notes to Financial Statements below, the financial statements of the Trust are prepared on a modified cash basis and differ from financial statements prepared in accordance with generally accepted accounting principles in that (a) revenues are recorded when received (generally within 15 days of the end of the preceding quarter) and distributions to Trust Unit holders are recorded when paid and (b) Trust expenses are recorded on an accrual basis. As a consequence, Trust royalty revenues for the fiscal year are based on Royalty Production during the twelve months ended September 30 of the fiscal year.

		Increase (decrease)		
	12 Months Ended 9/30/2012	**Amount**	**Percent**	**12 Months Ended 9/30/2011**
Average WTI Price	$ 95.65	$ 2.83	3.0	$ 92.82
Adjusted Chargeable Costs	$ 29.34	$ 1.70	6.2	$ 27.64
Average Production Taxes	$ 26.43	$ 0.69	2.7	$ 25.74
Average Per Barrel Royalty	$ 39.87	$ 0.42	1.1	$ 39.45
Average net royalty production (mb/d)	83.1	(2.3)	(2.7)	85.4

Average WTI prices rose 3.0% during the twelve months ended September 30, 2012, as compared to the preceding twelve-month period, fluctuating between an average price of $86.32 during October 2011 and an average price of $94.51 during September 2012, with a high average price of $106.16 during March 2012 and a low average price of $82.30 during June 2012. The increase in the

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Consumer Price Index used to calculate the Cost Adjustment Factor, as well as the scheduled increase in Chargeable Costs from $16.60 in calendar 2011 to $16.70 in calendar 2012, resulted in the increase in Adjusted Chargeable Costs during the twelve months ended September 30, 2012. The increase in Production Taxes during the twelve-month period was primarily due to the increase in Average WTI Price, which resulted in a higher average monthly production tax per barrel (see THE ROYALTY INTEREST Production Taxes in Item 1). The decline in the production levels from the 1989 Working Interest for the twelve-month period was primarily due to maintenance at the Prudhoe Bay field during the quarter ended September 30, 2012.

	Year Ended 12/31/2012	Increase (decrease) Amount	Percent	Year Ended 12/31/2011
		(Dollars in thousands)		
Royalty revenues	$ 200,019	($ 2,306)	(1.1)	$ 202,325
Cash earnings	$ 198,868	($ 2,241)	(1.1)	$ 201,109
Cash distributions	$ 198,885	($ 2,207)	(1.1)	$ 201,092
Administrative expenses	$ 1,152	($ 65)	(5.3)	$ 1,217
Trust corpus at year end	$ 826	($ 64)	(7.2)	$ 890

Despite the increase in average WTI Prices during the twelve months ended September 30, 2012, the decline in the production levels from the 1989 Working Interest due to maintenance at the Prudhoe Bay field during the quarter ended September 30, 2012 had a corresponding effect on royalty revenues, cash earnings and cash distributions for the twelve months ended December 31, 2012. The decrease in administrative expenses reflects certain decreases in the overall costs of supplies and services and timing differences in accruals of expenses.

2011 compared to 2010

	12 Months Ended 9/30/2011	Increase (decrease) Amount	Percent	12 Months Ended 9/30/2010
Average WTI Price	$ 92.82	$ 15.70	20.4	$ 77.12
Adjusted Chargeable Costs	$ 27.64	$ 3.89	16.4	$ 23.75
Average Production Taxes	$ 25.74	$ 7.33	39.8	$ 18.41
Average Per Barrel Royalty	$ 39.45	$ 4.48	12.8	$ 34.97
Average net royalty production (mb/d)	85.4	(2.3)	(2.6)	87.7

Average WTI prices rose 20.4% during the twelve months ended September 30, 2011, as compared to the preceding twelve-month period, fluctuating between a low average price of $81.89 during October 2010 and a high average price of $109.53 during April 2011 before receding to an average of $85.52 in September 2011. The scheduled increase in Chargeable Costs from $14.50 in calendar 2010 to $16.60 in calendar 2011 was the principal cause of the increase in Adjusted Chargeable costs during the twelve months ended September 30, 2011. The increase in Production Taxes during the twelve-month period was primarily to the increase in Average WTI Price, which resulted in a higher average monthly production tax per barrel (see THE ROYALTY INTEREST Production Taxes in Item 1).

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	Year Ended 12/31/2011	Increase (decrease) Amount	Percent	Year Ended 12/31/2010
		(Dollars in thousands)		
Royalty revenues	$ 202,325	$ 18,283	9.9	$ 184,042
Cash earnings	$ 201,109	$ 16,698	9.1	$ 184,411
Cash distributions	$ 201,092	($ 12,793)	(6.0)	$ 213,885
Administrative expenses	$ 1,217	($ 121)	(9.0)	$ 1,338
Trust corpus at year end	$ 890	$ 28	3.2	$ 862

The increase in average WTI Prices during the twelve months ended September 30, 2011 had a corresponding effect on royalty revenues for the twelve months ended December 31, 2011. Despite this increase in royalty revenues, there was a decrease in cash distributions for the twelve months ended December 31, 2011 due to the distribution to Unit holders in January of 2010 of approximately $29,469,000 under the May 2009 settlement agreement between the Trustee and BP Alaska relating to the August 2006 shutdown of the Prudhoe Bay field (see Note 7 of Notes to Financial Statements in Item 8).

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

The Trust is a passive entity and except for the Trust s ability to borrow money as necessary to pay liabilities of the Trust that cannot be paid out of cash on hand, the Trust is prohibited from engaging in borrowing transactions. The Trust periodically holds short-term investments acquired with funds held by the Trust pending distribution to Unit holders and funds held in reserve for the payment of Trust expenses and liabilities. Because of the short-term nature of these investments and limitations on the types of investments which may be held by the Trust, the Trust is not subject to any material interest rate risk. The Trust does not engage in transactions in foreign currencies which could expose the Trust or Unit holders to any foreign currency related market risk or invest in derivative financial instruments. It has no foreign operations and holds no long-term debt instruments.

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ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

BP PRUDHOE BAY ROYALTY TRUST

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Report of Independent Registered Public Accounting Firm

Trustee and Holders of Trust Units

BP Prudhoe Bay Royalty Trust:

We have audited the accompanying statements of assets, liabilities, and trust corpus of BP Prudhoe Bay Royalty Trust (the Trust) as of December 31, 2012 and 2011, and the related statements of cash earnings and distributions and changes in trust corpus for each of the years in the three-year period ended December 31, 2012. These financial statements are the responsibility of The Bank of New York Mellon Trust Company, N.A., as the Trust s trustee (the Trustee). Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by the Trustee, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

As described in note 2 to the financial statements, these financial statements were prepared on the modified cash basis of accounting, which is a comprehensive basis of accounting other than accounting principles generally accepted in the United States of America.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities, and trust corpus of the Trust as of December 31, 2012 and 2011, and its cash earnings and distributions and changes in trust corpus for each of the years in the three-year period ended December 31, 2012, in conformity with the modified cash basis of accounting described in note 2.

We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the Trust s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO), and our report dated March 1, 2013 expressed an unqualified opinion on the effectiveness of the Trust s internal control over financial reporting.

(signed) KPMG LLP

Dallas, Texas

March 1, 2013

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Report of Independent Registered Public Accounting Firm

Trustee and Holders of Trust Units

BP Prudhoe Bay Royalty Trust:

We have audited BP Prudhoe Bay Royalty Trust s internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). The Bank of New York Mellon Trust Company, N.A., as the Trust s trustee (the Trustee), is responsible for maintaining effective internal control over financial reporting and for its assessment of the effectiveness of internal control over financial reporting, included in the accompanying management s annual report on internal control over financial reporting. Our responsibility is to express an opinion on the Trust s internal control over financial reporting based on our audit.

We conducted our audit in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform the audit to obtain reasonable assurance about whether effective internal control over financial reporting was maintained in all material respects. Our audit included obtaining an understanding of internal control over financial reporting, assessing the risk that a material weakness exists, and testing and evaluating the design and operating effectiveness of internal control based on the assessed risk. Our audit also included performing such other procedures as we considered necessary in the circumstances. We believe that our audit provides a reasonable basis for our opinion.

The Trust s internal control over financial reporting is a process designed to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external purposes in accordance with the modified cash basis of accounting. The Trust s internal control over financial reporting includes those policies and procedures that (1) pertain to the maintenance of records that, in reasonable detail, accurately and fairly reflect the transactions and dispositions of the assets of the Trust; (2) provide reasonable assurance that transactions are recorded as necessary to permit preparation of financial statements in accordance with the modified cash basis of accounting, and that receipts and expenditures of the Trust are being made only in accordance with authorizations of the Trustee; and (3) provide reasonable assurance regarding prevention or timely detection of unauthorized acquisition, use, or disposition of the Trust s assets that could have a material effect on the financial statements.

Because of its inherent limitations, internal control over financial reporting may not prevent or detect misstatements. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

In our opinion, BP Prudhoe Bay Royalty Trust maintained, in all material respects, effective internal control over financial reporting as of December 31, 2012, based on criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission.

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We also have audited, in accordance with the standards of the Public Company Accounting Oversight Board (United States), the statements of assets, liabilities, and trust corpus of BP Prudhoe Bay Royalty Trust as of December 31, 2012 and 2011, and the related statements of cash earnings and distributions and changes in trust corpus for each of the years in the three-year period ended December 31, 2012, and our report dated March 1, 2013 expressed an unqualified opinion on those financial statements.

(signed) KPMG LLP

Dallas, Texas

March 1, 2013

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BP Prudhoe Bay Royalty Trust

Statement of Assets, Liabilities and Trust Corpus

(Prepared on a modified basis of cash receipts and disbursements)

(In thousands, except unit data)

	December 31, 2012	December 31, 2011
Assets		
Cash and cash equivalents (Note 2)	$ 1,001	$ 1,018
Total assets	$ 1,001	$ 1,018
Liabilities and Trust Corpus		
Accrued expenses	$ 175	$ 128
Trust corpus (40,000,000 units of beneficial interest authorized, 21,400,000 units issued and outstanding)	826	890
Total liabilities and trust corpus	$ 1,001	$ 1,018

See accompanying notes to financial statements.

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BP Prudhoe Bay Royalty Trust

Statements of Cash Earnings and Distributions

(Prepared on a modified basis of cash receipts and disbursements)

(In thousands, except unit data)

	Year Ended December 31, 2012	2011	2010
Royalty revenues	$ 200,019	$ 202,325	$ 184,042
Litigation expense reimbursement (Note 7)		$	1,705
Interest income	1	1	2
Less: Trust administrative expenses	(1,152)	(1,217)	(1,338)
Cash earnings	$ 198,868	$ 201,109	$ 184,411
Cash distributions	$ 198,885	$ 201,092	$ 213,885
Cash distributions per unit	$ 9.294	$ 9.397	$ 9.995
Units outstanding	21,400,000	21,400,000	21,400,000

See accompanying notes to financial statements.

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BP Prudhoe Bay Royalty Trust

Statements of Changes in Trust Corpus

(Prepared on a modified basis of cash receipts and disbursements)

(In thousands)

	Year Ended December 31,		
	2012	**2011**	**2010**
Trust corpus at beginning of year	$ 890	$ 862	$ 32,273
Cash earnings	198,868	201,109	184,411
(Increase) decrease in accrued expenses	(47)	11	72
Cash distributions	(198,885)	(201,092)	(213,885)
Amortization of royalty interest			(2,009)
Trust corpus at end of year	$ 826	$ 890	$ 862

See accompanying notes to financial statements.

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BP Prudhoe Bay Royalty Trust

Notes to Financial Statements

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

(1) Formation of the Trust and Organization

BP Prudhoe Bay Royalty Trust (the Trust), a grantor trust, was created as a Delaware statutory trust pursuant to a Trust Agreement dated February 28, 1989 among the Standard Oil Company (Standard Oil), BP Exploration (Alaska) Inc. (BP Alaska), The Bank of New York Mellon, as trustee, and BNY Mellon Trust of Delaware (successor to The Bank of New York (Delaware)), as co-trustee. On December 15, 2010, The Bank of New York Mellon resigned as trustee and was replaced by The Bank of New York Mellon Trust Company, N.A., a national banking association, as successor trustee (the Trustee). Standard Oil and BP Alaska are indirect wholly owned subsidiaries of BP p.l.c. (BP).

On February 28, 1989, Standard Oil conveyed an overriding royalty interest (the Royalty Interest) to the Trust. The Trust was formed for the sole purpose of owning and administering the Royalty Interest. The Royalty Interest represents the right to receive, effective February 28, 1989, a per barrel royalty (the Per Barrel Royalty) of 16.4246% on the lesser of (a) the first 90,000 barrels of the average actual daily net production of oil and condensate per quarter or (b) the average actual daily net production of oil and condensate per quarter from BP Alaska s working interest as of February 28, 1989 in the Prudhoe Bay field, located on the North Slope of Alaska. Trust Unit holders will remain subject at all times to the risk that production will be interrupted or discontinued. BP has guaranteed the performance of BP Alaska of its payment obligations with respect to the Royalty Interest.

Effective January 1, 2000, BP Alaska and all other Prudhoe Bay working interest owners cross-assigned interests in the Prudhoe Bay field pursuant to the Prudhoe Bay Unit Alignment Agreement. BP Alaska retained all rights, obligations, and liabilities associated with the Trust.

The trustees of the Trust are The Bank of New York Mellon Trust Company, N.A. and BNY Mellon Trust of Delaware. BNY Mellon Trust of Delaware serves as co-trustee in order to satisfy certain requirements of the Delaware Statutory Trust Act. The Bank of New York Mellon Trust Company, N.A. alone is able to exercise the rights and powers granted to the Trustee in the Trust Agreement.

The Per Barrel Royalty in effect for any day is equal to the price of West Texas Intermediate crude oil (the WTI Price) for that day less scheduled Chargeable Costs (adjusted for inflation) and Production Taxes (based on statutory rates then in existence).

The Trust is passive, with the Trustee having only such powers as are necessary for the collection and distribution of revenues, the payment of Trust liabilities, and the protection of the Royalty Interest. The Trustee, subject to certain conditions, is obligated to establish cash reserves and borrow funds to pay liabilities of the Trust when they become due. The Trustee may sell Trust properties only (a) as authorized by a vote of the Trust unit holders, (b) when necessary to provide for the payment of specific liabilities of the Trust then due (subject to certain conditions) or (c) upon termination of the Trust. Each Trust Unit issued and outstanding represents an equal undivided share of beneficial interest in the Trust. Royalty payments are received by the Trust and distributed to Trust Unit holders, net of Trust expenses, in the month succeeding the end of each calendar quarter. The Trust will terminate (i) upon a vote of Trust unit holders of not less than 60% of the outstanding Trust units, or (ii) at such time the net revenues from the Royalty Interest for two successive years are less than $1,000,000 per year (unless the net revenues during such period are materially and adversely affected by certain events).

BP Prudhoe Bay Royalty Trust

Notes to Financial Statements

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

In order to ensure the Trust has the ability to pay future expenses, the Trust established a cash reserve account which the Trustee believes is sufficient to pay approximately one year s current and expected liabilities and expenses of the Trust.

(2) Basis of Accounting

The financial statements of the Trust are prepared on a modified cash basis and reflect the Trust s assets, liabilities, corpus, earnings, and distributions, as follows:

a. Revenues are recorded when received (generally within 15 days of the end of the preceding quarter) and distributions to Trust unit holders are recorded when paid.

b. Trust expenses (which include accounting, engineering, legal, and other professional fees, trustees fees, and out-of-pocket expenses) are recorded on an accrual basis.

c. Cash reserves may be established by the Trustee for certain contingencies that would not be recorded under generally accepted accounting principles.

While these statements differ from financial statements prepared in accordance with accounting principles generally accepted in the United States of America, the modified cash basis of reporting revenues and distributions is considered to be the most meaningful because quarterly distributions to the Trust unit holders are based on net cash receipts. The accompanying modified cash basis financial statements contain all adjustments necessary to present fairly the assets, liabilities and corpus of the Trust as of December 31, 2012 and 2011, and the modified cash earning and distributions and changes in Trust corpus for the years ended December 31, 2012, 2011 and 2010. The adjustments are of a normal recurring nature and are, in the opinion of the Trustee, necessary to fairly present the results of operations.

As of December 31, 2012 and 2011, cash equivalents which represent the cash reserve consist of U.S. treasury bills with an initial term of less than three months.

Estimates and assumptions are required to be made regarding assets, liabilities and changes in Trust corpus resulting from operations when financial statements are prepared. Changes in the economic environment, financial markets and any other parameters used in determining these estimates could cause actual results to differ, and the difference could be material.

(3) Royalty Interest

At inception in February 1989, the Royalty Interest held by the Trust had a carrying value of $535,000,000. In accordance with generally accepted accounting principles, the Trust amortized the value of the Royalty Interest based on the units of production method. Such amortization was charged directly to the Trust corpus, and did not affect cash earnings. The daily rate for amortization per net equivalent barrel of oil for the year ended December 31, 2010 was $0.38. In addition, the Trust periodically evaluated impairment of the Royalty Interest by comparing the undiscounted cash flows expected to be realized from the Royalty Interest to the carrying value, pursuant to the Financial Accounting Standards Board Accounting Standards Codification (ASC) 360, *Property, Plant, and Equipment*. If the expected future undiscounted cash flows were less than the carrying value, the Trust recognized impairment losses for the difference between the carrying value and the estimated fair value of the Royalty Interest. By December 31, 2010, the Trust had recognized accumulated amortization of $359,473,000 and aggregate impairment write-downs of $175,527,000 reducing the carrying value of the Royalty Interest to zero.

BP Prudhoe Bay Royalty Trust

Notes to Financial Statements

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

(4) Income Taxes

The Trust files its federal tax return as a grantor trust subject to the provisions of subpart E of Part I of Subchapter J of the Internal Revenue Code of 1986, as amended, rather than as an association taxable as a corporation. The Trust unit holders are treated as the owners of Trust income and corpus, and the entire taxable income of the Trust will be reported by the Trust unit holders on their respective tax returns.

If the Trust were determined to be an association taxable as a corporation, it would be treated as an entity taxable as a corporation on the taxable income from the Royalty Interest, the Trust unit holders would be treated as shareholders, and distributions to Trust unit holders would not be deductible in computing the Trust s tax liability as an association.

(5) Alaska Oil and Gas Production Tax

The Alaska oil and gas production tax statutes were amended by a bill (the 2006 Amendments) which became effective in August 2006. The 2006 Amendments replaced an oil production tax levied at the flat rate of 15% of the gross value at the point of production (the wellhead or field value) of taxable oil produced from a producer s leases or properties in the State of Alaska. Under the 2006 Amendments, producers were taxed on the production tax value of taxable oil (gross value at the point of production for the calendar year less the producer s direct costs of exploring for, developing, or producing oil or gas deposits located within the producer s leases or properties in Alaska for the year) at a rate equal to the sum of 22.5% plus a progressivity rate determined by the average monthly production tax value of the oil produced. The progressivity rate imposed by the 2006 Amendments was equal to 0.25% times the amount by which the simple average for each calendar month of the daily production tax values per barrel of the oil produced during the month exceeded $40 per barrel.

In December 2007, a bill (popularly titled Alaska s Fair and Equitable Share or ACES) took effect which further amended the Alaska oil and gas production tax statutes in certain respects. ACES changed the basic tax rate from 22.5% to 25% and increased the progressivity rate. If the producer s average monthly production tax value per barrel is greater than $30 but not more than $92.50, the progressivity tax rate is 0.4% times the amount by which the average monthly production tax value exceeds $30 per barrel. If the producer s average monthly production tax value per barrel is greater than $92.50, the progressivity tax rate is the sum of 25% and the product of 0.1% multiplied by the difference between the average monthly production tax value per barrel and $92.50, except that the sum may not exceed 50%.

The Trustee and BP Alaska entered into a letter agreement in October 2006 and an amendment thereto in January 2008 (the Letter Agreement) to resolve issues associated with the 2006 Amendments and ACES. The Letter Agreement modified the calculation of Production Taxes in the daily Per Barrel Royalty calculation effective as of August 20, 2006, in the case of the 2006 Amendments, and effective December 20, 2007, in the case of ACES. It also provides that the retroactivity provisions of the respective tax bills are not applicable to the Per Barrel Royalty calculation for periods prior to the effective dates of the 2006 Amendments and ACES.

BP Prudhoe Bay Royalty Trust

Notes to Financial Statements

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

(6) Legal Expenses

The Trust incurred legal and other expenses as a result of litigation and other issues arising out of the August 2006 shutdown of the Prudhoe Bay field. Legal fees and expenses related to the Trust s legal matters contributed to the Trust administrative expenses during 2010.

(7) Claims Settlement and Litigation Expense Reimbursement

In May 2009, the Trustee entered into a settlement agreement with BP Alaska to resolve certain issues related to the temporary shutdown of the Prudhoe Bay field in August 2006 following oil spills and to compromise any claims that the Trust and past, present and future holders of Trust Units might have had relating to conduct by BP Alaska that may have resulted in a reduction of the royalty payments received by the Trust in 2006, 2007 and 2008. Under the settlement agreement, BP Alaska paid approximately $29,469,000 into an interest-bearing escrow account pending final dismissal of certain litigation and court approval of the settlement agreement. In December 2009, the settlement amount and accrued interest, totaling approximately $29,474,000, was released from escrow and paid to the Trust. This amount, together with BP Alaska s royalty payment with respect to the quarter ended December 31, 2009 was distributed to Unit holders in January 2010.

The Trust incurred legal fees and expenses as a result of litigation and other issues arising out of the shutdown of the Prudhoe Bay field. Under the settlement agreement, BP Alaska agreed to pay the Trustee its reasonable attorneys fees and expenses, including internal expenses and expert fees, incurred in its investigation of the claims that are the subject of the settlement agreement, in responding to subpoenas, in defending a lawsuit, and in seeking court approval of the settlement agreement. In February 2010, BP Alaska paid the Trustee approximately $1,705,000 as reimbursement of those expenses. Except for potential continuing legal fees and expenses, the Trustee does not anticipate any other loss contingency resulting from the shutdown of the Prudhoe Bay field.

(8) Royalty Revenue Adjustments

Certain royalty payments received by the Trust in 2012, 2011 and 2010 were adjusted by BP Alaska to compensate for underpayments or overpayments of the royalties due with respect to the quarters ended prior to the dates of such payments. Average net production of crude oil and condensate from the proved reserves allocated to the Trust was less than 90,000 barrels per day during certain quarters. Royalty payments by BP Alaska with respect to those quarters were based on estimates by BP Alaska of production levels because actual data was not available by the dates on which payments were required to be made to the Trust. Subsequent recalculation by BP Alaska of royalty payments due based on actual production data resulted in the payment adjustments shown in the table below (in thousands):

	2012 Payments Received			
	January	**April**	**July**	**October**
Royalty payment as calculated	$ 53,690	$ 56,890	$ 50,011	$ 38,987
Adjustment for underpayment (overpayment), plus accrued interest	254			187
Net payment received	$ 53,944	$ 56,890	$ 50,011	$ 39,174

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BP Prudhoe Bay Royalty Trust

Notes to Financial Statements

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

	2011 Payments Received			
	January	April	July	October
Royalty payment as calculated	$ 51,645	$ 51,726	$ 56,783	$ 42,186
Adjustment for underpayment (overpayment), plus accrued interest	16		(31)	
Net payment received	$ 51,661	$ 51,726	$ 56,752	$ 42,186

	2010 Payments Received			
	January	April	July	October
Royalty payment as calculated	$ 47,862	$ 47,136	$ 45,462	$ 43,496
Adjustment for underpayment (overpayment), plus accrued interest	159			(73)
Net payment received	$ 48,021	$ 47,136	$ 45,462	$ 43,423

(9) Subsequent Event

In January 2013, the Trust received a payment of $49,712,357 from BP Alaska. This payment consisted of $50,560,556, representing the royalty payment due with respect to the Trust s Royalty Interest for the quarter ended December 31, 2012, minus $848,199, representing the amount of an overpayment by BP Alaska, including interest on the overpayment, of the royalty payment due with respect to the quarter ended September 30, 2012. On January 18, 2013, after deducting Trust administrative expenses, the Trustee distributed $49,545,447 to Unit holders of record on January 15, 2013.

Subsequent events have been evaluated through the date of the annual report on Form 10-K in which these financial statements are included.

(10) Summary of Quarterly Results (Unaudited)

A summary of selected quarterly financial information for the years ended December 31, 2012, 2011, and 2010 is as follows (in thousands, except unit data):

	2012 Fiscal Quarter			
	First	Second	Third	Fourth
Royalty revenues	$ 53,944	$ 56,890	$ 50,011	$ 39,174
Interest income				1
Trust administrative expenses	(117)	(326)	(517)	(192)
Cash earnings	53,827	56,564	49,494	38,983
Cash distributions	53,845	56,562	49,496	38,982
Cash distributions per unit	2.5161	2.6431	2.3129	1.8216

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BP Prudhoe Bay Royalty Trust

Notes to Financial Statements

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

	2011 Fiscal Quarter			
	First	**Second**	**Third**	**Fourth**
Royalty revenues	$ 51,661	$ 51,726	$ 56,752	$ 42,186
Interest income		1		
Trust administrative expenses	(86)	(556)	(276)	(299)
Cash earnings	51,575	51,171	56,476	41,887
Cash distributions	51,531	51,216	56,476	41,869
Cash distributions per unit	2.4080	2.3933	2.6391	1.9565

	2010 Fiscal Quarter			
	First	**Second**	**Third**	**Fourth**
Royalty revenues	$ 48,021	$ 47,136	$ 45,462	$ 43,423
Litigation expense reimbursement	1,705			
Interest income	1		1	
Trust administrative expenses	(202)	(330)	(621)	(185)
Cash earnings	49,525	46,806	44,842	43,238
Cash distributions	77,295	48,511	44,841	43,238
Cash distributions per unit	3.6119	2.2669	2.0954	2.0205

BP Prudhoe Bay Royalty Trust

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

(11) Supplemental Reserve Information and Standardized Measure of Discounted Future Net Cash Flow Relating to Proved Reserves (Unaudited)

Pursuant to Statement of FASB ASC 932, *Extractive Activities Oil and Gas*, the Trust is required to include in its financial statements supplementary information regarding estimates of quantities of proved reserves attributable to the Trust and future net cash flows. The following information in this note reflects the adoption of Securities Exchange Act Release No. 59192, *Modernization of Oil and Gas Reporting* which became effective for financial statements for fiscal years ending on or after December 31, 2009.

Estimates of proved reserves are inherently imprecise and subjective and are revised over time as additional data becomes available. Such revisions may often be substantial. Information regarding estimates of proved reserves attributable to the combined interests of BP Alaska and the Trust were based on reserve estimates prepared by BP Alaska. BP Alaska s reserve estimates are believed to be reasonable and consistent with presently known physical data concerning the size and character of the Prudhoe Bay field.

There is no precise method of allocating estimates of physical quantities of reserve volumes between BP Alaska and the Trust, since the Royalty Interest is not a working interest and the Trust does not own and is not entitled to receive any specific volume of reserves from the Prudhoe Bay field. Reserve volumes attributable to the Trust were estimated by allocating to the Trust its share of estimated future production from the field, based on the 12-month average WTI Price for 2012 (94.71), 2011 ($96.19 per barrel) and 2010 ($79.43 per barrel). Because the reserve volumes attributable to the Trust are estimated using an allocation of reserve volumes based on the estimated future production and on the current WTI Price, a change in the timing of estimated production or a change in the WTI price will result in a change in the Trust s estimated reserve volumes. Therefore, the estimated reserve volumes attributable to the Trust will vary if different production estimates and prices are used.

In addition to production estimates and prices, reserve volumes attributable to the Trust are affected by the amount of Chargeable Costs that will be deducted in determining the Per Barrel Royalty. Net proved reserves of oil and condensate attributable to the Trust as of December 31, 2012, 2011 and 2010, based on BP Alaska s latest reserve estimate at such times and the 12-month average WTI prices for 2012, 2011 and 2010, were estimated to be 76, 82 and 78 million barrels, respectively (of which 71, 73 and 67 million barrels, respectively, are proved developed reserves). Under the provisions of FASB ASC 932, no consideration can be given to reserves not considered proved at the present time.

The standardized measure of discounted future net cash flow relating to proved reserves disclosure required by FASB ASC 932 assigns monetary amounts to proved reserves based on current prices. This discounted future net cash flow should not be construed as the current market value of the Royalty Interest. A market valuation determination would include, among other things, anticipated price changes and the value of additional reserves not considered proved at the present time or reserves that may be produced after the currently anticipated end of field life. At December 31, 2012, 2011and 2010, the standardized measure of discounted future net cash flow relating to proved reserves attributable to the Trust (estimated in accordance with the provisions of FASB ASC 932), based on the 12-month average WTI Prices for 2012, 2011 and 2010 of $94.71, $96.19 and $79.43 per barrel, respectively, scheduled chargeable costs in future years and production taxes were as follows (in thousands):

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BP Prudhoe Bay Royalty Trust

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

	December 31, 2012	2011	2010
Future cash inflows	$ 2,175,986	$ 2,460,471	$ 1,992,585
10% annual discount for estimated timing of cash flows	(861,128)	(1,027,358)	(806,097)
Standardized measure of discounted future net cash flow (a)	$ 1,314,858	$ 1,433,113	$ 1,186,488

(a) The following are the principal sources of the change in the standardized measure of discounted future net cash flows (in thousands):

	December 31, 2012	2011	2010
Net changes in prices and production costs	(109,360)	704,603	790,623
Net change in production taxes	53,634	(366,032)	(327,680)
Other	(630)	212	94
	(56,356)	338,783	463,037
Royalty income received (b)	(186,676)	(195,087)	(196,766)
Accretion of discount	124,777	102,929	83,656
Net increase (decrease) during the year	$ (118,255)	$ 246,625	$ 349,927

(b) For the purpose of this calculation, royalty income received for 2012, 2011 and 2010 includes the following:

Period October 1, 2012 through December 31, 2012	$ 49,712
Period October 1, 2011 through December 31, 2011	$ 53,944
Period October 1, 2010 through December 31, 2010	$ 51,660

The above royalty income was received by the Trust in January 2013, 2012 and 2011, respectively.

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BP Prudhoe Bay Royalty Trust

(Prepared on a modified basis of cash receipts and disbursements)

December 31, 2012

The changes in estimated quantities of proved oil and condensate were as follows:

Proved developed and undeveloped reserves (thousands of barrels) as of:	
December 31, 2009	68,144
Revisions of previous estimates (1)	15,388
Production	(5,257)
December 31, 2010	78,275
Revisions of previous estimates (2)	9,150
Production	(5,121)
December 31, 2011	82,304
Revisions of previous estimates (3)	(1,791)
Production	(4,996)
December 31, 2012	75,517
Proved developed reserves (thousands of barrels) as of:	
December 31, 2010	67,401
December 31, 2011	73,476
December 31, 2012	70,676
Proved undeveloped reserves (thousands of barrels) as of:	
December 31, 2010	10,874
December 31, 2011	8,828
December 31, 2012	4,841

(1) The positive revision in year-end 2010 reserves reflects an increase in the WTI Price from $61.18 per barrel for 2009 to $79.43 per barrel for 2010 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2009 and 2010, respectively.

(2) The positive revision in year-end 2011 reserves reflects an increase in the WTI Price from $79.43 per barrel for 2010 to $96.19 per barrel for 2011 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2010 and 2011, respectively.

(3) The negative revision in year-end 2012 reserves reflects a decrease in the WTI Price from $96.19 per barrel for 2011 to $94.71 per barrel for 2012 using the 12-month average of the first-day-of-the-month price for each month in the years ended December 31, 2011 and 2012, respectively.

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ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

There have been no changes in accountants and no disagreements with accountants on any matter of accounting principles or practices or financial statement disclosures during the two fiscal years ended December 31, 2012.

ITEM 9A. CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Trustee has disclosure controls and procedures (as defined in Rule 13a-15(e) and Rule 15d-15(e) under the Exchange Act) that are designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is recorded, processed, summarized and reported, within the time periods specified in the SEC s rules and forms. These controls and procedures include but are not limited to controls and procedures designed to ensure that information required to be disclosed by the Trust in the reports that it files or submits under the Exchange Act is accumulated and communicated to the responsible trust officers of the Trustee to allow timely decisions regarding required disclosure.

Under the terms of the Trust Agreement and the Conveyance, BP Alaska has significant disclosure and reporting obligations to the Trust. BP Alaska is required to provide the Trust such information concerning the Royalty Interest as the Trustee may need and to which BP Alaska has access to permit the Trust to comply with any reporting or disclosure obligations of the Trust pursuant to applicable law and the requirements of any stock exchange on which the Units are issued. These reporting obligations include furnishing the Trust a report by February 28 of each year containing all information of a nature, of a standard and in a form consistent with the requirements of the SEC respecting the inclusion of reserve and reserve valuation information in filings under the Exchange Act and with applicable accounting rules. The report is required to set forth, among other things, BP Alaska s estimates of future net cash flows from proved reserves attributable to the Royalty Interest, the discounted present value of such proved reserves and the assumptions utilized in arriving at the estimates contained in the report.

In addition, the Conveyance gives the Trust certain rights to inspect the books and records of BP Alaska and discuss the affairs, finances and accounts of BP Alaska relating to the 1989 Working Interests with representatives of BP Alaska; it also requires BP Alaska to provide the Trust with such other information as the Trustee may reasonably request from time to time and to which BP Alaska has access.

The Trustee s disclosure controls and procedures include ensuring that the Trust receives the information and reports that BP Alaska is required to furnish to the Trust on a timely basis, that the appropriate responsible personnel of the Trustee examine such information and reports, and that information requested from and provided by BP Alaska is included in the reports that the Trust files or submits under the Exchange Act.

As of the end of calendar year 2012, the trust officers of the Trustee responsible for the administration of the Trust conducted an evaluation of the Trust s disclosure controls and procedures. Their evaluation considered, among other things, that the Trust Agreement and the Conveyance impose enforceable legal obligations on BP Alaska, and that BP Alaska has provided the information required by those agreements and other information requested by the Trustee from time to time on a timely basis. The officers concluded that the Trust s disclosure controls and procedures are effective.

Internal Control Over Financial Reporting

Management s Annual Report on Internal Control Over Financial Reporting. The Bank of New York Mellon, as Trustee of the Trust, is responsible for establishing and maintaining adequate internal control over financial reporting, as such term is defined in Rule 13a-15(f) promulgated under the Exchange Act. The Trustee conducted an evaluation of the effectiveness of the Trust s internal control over financial reporting based on the criteria established in *Internal Control Integrated Framework* issued by the Committee of Sponsoring Organizations of the Treadway Commission (the COSO criteria). Based on the Trustee s evaluation under the COSO criteria, the Trustee concluded that the Trust s internal control over financial reporting was effective as of December 31, 2012.

The effectiveness of the Trust s internal control over financial reporting as of December 31, 2012 has been audited by KPMG LLP, an independent registered public accounting firm, as stated in their report set forth in full above on page 36.

Changes in Internal Control Over Financial Reporting. There has not been any change in the Trust s internal control over financial reporting identified in connection with the Trustee s evaluation of the Trust s internal control over financial reporting that occurred during the Trust s fourth fiscal quarter that has materially affected, or is reasonably likely to materially affect, the Trust s internal control over financial reporting.

ITEM 9B. OTHER INFORMATION

Not applicable.

PART III

ITEM 10. DIRECTORS, EXECUTIVE OFFICERS AND CORPORATE GOVERNANCE

The Trust has no directors or executive officers. The Trust is administered by the Trustee under the authority granted it in the Trust Agreement. The Trust Agreement grants the Trustee only the rights and powers necessary to achieve the purposes of the Trust. See THE TRUST Duties and Powers of Trustee in Item 1.

The Trustee may be removed with or without cause by vote of holders of a majority of the Units at a meeting called and held as provided in the Trust Agreement. At the meeting the Unit holders may appoint a successor trustee meeting the requirements set forth in the Trust Agreement. See THE TRUST Resignation or Removal of Trustee in Item 1.

The Trust has not adopted a code of ethics. The standards of conduct governing the Trustee are set forth in the Trust Agreement and Delaware law. Ethical standards applicable to the employees of the Trustee are set forth in the Code of Conduct which may be found at http://www.bnymellon.com/ethics.

There is no audit committee or committee performing comparable functions responsible for reviewing the audited financial statements of the Trust.

ITEM 11. EXECUTIVE COMPENSATION

The Trust has no directors, officers or employees to whom it pays compensation. The Trust is administered by employees of the Trustee in the ordinary course of their employment who receive no compensation specifically related to their services to the Trust.

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Under the Trust Agreement, the Trustee is entitled to receive on each Quarterly Record Date a quarterly fee, currently consisting of: (i) a quarterly administrative fee of $.0017 per Unit outstanding on the Quarterly Record Date plus $10.00 for each payment by wire transfer to a Unit holder and (ii) a transfer service fee of $2.42 per Unit holder account as of the Quarterly Record Date. Both the administrative service fee and the transfer service fee are subject to increase in each calendar year by the proportionate increase, if any, during the preceding calendar year in the Consumer Price Index (as defined in the Conveyance; see THE ROYALTY INTEREST Cost Adjustment Factor in Item 1) during the preceding calendar year. The Trustee also bills the Trust for certain reimbursable expenses. There is no compensation committee or committee performing similar functions with authority to determine any compensation of the Trustee other than the fees and reimbursable expenses provided for in the Trust Agreement.

The compensation received by the Trustee from the Trust during the three fiscal years ended December 31, 2012 was as follows:

Year ended December 31,	Trustee s Fees	Transfer Agent and Registrar Fees
2010	$ 155,430	$ 5,291
2011	155,430	4,751
2012	155,428	

ITEM 12. SECURITY OWNERSHIP OF CERTAIN BENEFICIAL OWNERS AND MANAGEMENT AND RELATED UNITHOLDER MATTERS

Securities Authorized for Issuance under Equity Compensation Plans

No Units are authorized for issuance under any form of equity compensation plan.

Unit Ownership of Certain Beneficial Owners

As of February 24, 2013, there were no persons known to the Trustee to be the beneficial owners of more than five percent of the Units.

Unit Ownership of Management

Neither BP Alaska, Standard Oil, nor BP owns any Units. No Units are owned by The Bank of New York Mellon Trust Company, N.A., as Trustee or in its individual capacity, or by BNY Mellon Trust of Delaware, as co-trustee or in its individual capacity.

Changes in Control

The Trustee knows of no arrangement, including the pledge of Units, the operation of which may at a subsequent date result in a change in control of the Trust.

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ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS, AND DIRECTOR INDEPENDENCE

There has been no transaction by the Trust since the beginning of 2011, or any currently proposed transaction in which a related person (as defined in Item 404 of Regulation S-K) had or will have a direct or indirect material interest, except for payment to the Trustee of the fees and reimbursement for expenses prescribed in the Trust Agreement. See Item 11 above.

The Trust has no independent directors. See Item 10 above.

ITEM 14. PRINCIPAL ACCOUNTANT FEES AND SERVICES

Fees for services performed by KPMG LLP for the years ended December 31, 2012 and 2011 are:

	2012	2011
Audit	$ 153,000	$ 149,716
Audit related	$ 20,000	20,000
Tax	$ 206,332	203,606
Other		
	$ 379,332	$ 373,322

The Trust has no audit committee, and as a consequence, has no audit committee pre-approval policy with respect to fees paid to KPMG LLP.

ITEM 15. EXHIBITS AND FINANCIAL STATEMENT SCHEDULES

(a) FINANCIAL STATEMENTS
The following financial statements of the Trust are included in Part II, Item 8:

Report of Independent Registered Public Accounting Firm

Statements of Assets, Liabilities and Trust Corpus as of December 31, 2012 and 2011

Statements of Cash Earnings and Distributions for the years ended December 31, 2012, 2011 and 2010

Statements of Changes in Trust Corpus for the years ended December 31, 2012, 2011 and 2010

Notes to Financial Statements

(b) FINANCIAL STATEMENT SCHEDULES
All financial statement schedules have been omitted because they are either not applicable, not required or the information is set forth in the financial statements or notes thereto.

(c) EXHIBITS

4.1

BP Prudhoe Bay Royalty Trust Agreement dated February 28, 1989 among The Standard Oil Company, BP Exploration (Alaska) Inc., The Bank of New York Trustee, and F. James Hutchinson, Co-Trustee.

4.2 Overriding Royalty Conveyance dated February 27, 1989 between BP Exploration (Alaska) Inc. and The Standard Oil Company.

4.3 Trust Conveyance dated February 28, 1989 between The Standard Oil Company and BP Prudhoe Bay Royalty Trust.

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4.4 Support Agreement dated as of February 28, 1989, as amended May 8, 1989, among The British Petroleum Company p.l.c., BP Exploration (Alaska) Inc., The Standard Oil Company and BP Prudhoe Bay Royalty Trust.

4.5 Letter agreement executed October 13, 2006 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee.

4.6 Letter agreement executed January 11, 2008 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee.

10.1 Settlement Agreement, dated May 8, 2009, among BP Exploration (Alaska) Inc., The Bank of New York Mellon, as Trustee, and BNY Mellon Trust Company of Delaware, as Co-Trustee.

10.2 Agreement of Resignation, Appointment and Acceptance dated as of December 15, 2010 among BP Exploration (Alaska) Inc., The Bank of New York Mellon and The Bank of New York Mellon Trust Company, N.A.

31 Rule 13a-14(a) certification.

32 Section 1350 certification.

99 Report of Miller and Lents, Ltd., dated February 15, 2013.

101 *Explanatory note:* An Interactive Data File is not submitted with this filing pursuant to Item 601(101) of Regulation S-K, because the Trust does not prepare its financial statements in accordance with generally accepted accounting principles as used in the United States. See Note 2 of Notes to Financial Statements in Part II, Item 8.

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SIGNATURES

Pursuant to the requirements of the Securities Exchange Act of 1934, the Registrant has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized.

BP PRUDHOE BAY ROYALTY TRUST

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

By: /s/ Mike Ulrich
Mike Ulrich

Vice President

March 1, 2013

The Registrant is a trust and has no officers, directors, or persons performing similar functions. No additional signatures are available and none have been provided.

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INDEX TO EXHIBITS

Exhibit No.	Description
4.1	BP Prudhoe Bay Royalty Trust Agreement dated February 28, 1989 among The Standard Oil Company, BP Exploration (Alaska) Inc., The Bank of New York, Trustee, and F. James Hutchinson, Co-Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).
4.2	Overriding Royalty Conveyance dated February 27, 1989 between BP Exploration (Alaska) Inc. and The Standard Oil Company. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).
4.3	Trust Conveyance dated February 28, 1989 between The Standard Oil Company and BP Prudhoe Bay Royalty Trust. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).
4.4	Support Agreement dated as of February 28, 1989 among The British Petroleum Company p.l.c., BP Exploration (Alaska) Inc., The Standard Oil Company and BP Prudhoe Bay Royalty Trust. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2006 (File No. 1-10243).
4.5	Letter agreement executed October 13, 2006 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Quarterly Report on Form 10-Q for the quarter ended September 30, 2006 (File No. 1-10243).
4.6	Letter agreement executed January 11, 2008 between BP Exploration (Alaska) Inc. and The Bank of New York, as Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Current Report on Form 8-K dated January 11, 2008 (File No. 1-10243).
10.1	Settlement Agreement, dated May 8, 2009, among BP Exploration (Alaska) Inc., The Bank of New York Mellon, as Trustee, and BNY Mellon Trust Company of Delaware, as Co-Trustee. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Current Report on Form 8-K dated May 8, 2009 (File No. 1-10243).
10.2	Agreement of Resignation, Appointment and Acceptance dated as of December 15, 2010 among BP Exploration (Alaska) Inc., The Bank of New York Mellon and The Bank of New York Mellon Trust Company, N.A. Incorporated by reference to the correspondingly numbered exhibit to the Registrant s Annual Report on Form 10-K for the fiscal year ended December 31, 2010 (File No. 1-10243).
31*	Rule 13a-14(a) certification.
32*	Section 1350 certification.
99*	Report of Miller and Lents, Ltd., dated February 15, 2013.

* Filed herewith.