FORM 10-K405

BP PRUDHOE BAY ROYALTY TRUST - BPT

Filed: March 31, 1995 (period: December 31, 1994)

Annual report filed under Regulation S-K Item 405 (Discontinued)

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, 1994

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 incorporation or organization)	(I.R.S. Employer Identification No.)

THE BANK OF NEW YORK, TRUSTEE 101 BARCLAY STREET, 21ST FLOOR WEST NEW YORK, NEW YORK	10286
(Address of principal executive offices)	(Zip Code)

Registrants telephone number, including area code: (212) 815-5092

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 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 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/

As of March 8, 1995, 21,400,000 Units of Beneficial Interest were outstanding, and the aggregate market value of Units (based upon the closing price of the Units on the New York Stock Exchange as reported in The Wall Street Journal) held by nonaffiliates was approximately $366,475,000.

Documents Incorporated by Reference: None

TABLE OF CONTENTS

PART II

PART I

ITEM 1. BUSINESS

DESCRIPTION OF THE TRUST

BP Prudhoe Bay Royalty Trust (the "Trust"), a grantor trust, was created as a Delaware business trust. The Trust has been established by The Standard Oil Company ("Standard Oil") and is administered by The Bank of New York, as trustee (collectively with the co-trustee located in Delaware, the "Trustee"), pursuant to the BP Prudhoe Bay Royalty Trust Agreement dated February 28, 1989 by and among Standard Oil, BP Exploration (Alaska) Inc. (the "Company") and the Trustee (the "Trust Agreement"). The Company and Standard Oil are indirect, wholly owned subsidiaries of The British Petroleum Company p.l.c. ("BP"). The Trustee's offices are located at 101 Barclay Street, New York, New York 10286 and its telephone number is (212) 815-5092.

Upon creation of the Trust, the Trust acquired an overriding royalty interest (the "Royalty Interest"), which entitles the Trust to a Per Barrel Royalty, as defined herein, on 16.4246% of the first 90,000 barrels of the average actual daily net production of oil and condensate per quarter (the "Royalty Production") from the Company's working interest in the Prudhoe Bay Unit (the "PBU"). The Royalty Interest was conveyed to Standard Oil pursuant to the terms of an Overriding Royalty Conveyance dated February 27, 1989 (the "Overriding Conveyance") and from Standard Oil to the Trust by a Trust Conveyance dated February 28, 1989 (the "Trust Conveyance"). The Overriding Conveyance and the Trust Conveyance are herein collectively referred to as the "Conveyance". The Royalty Interest is free of any exploration and development expenditures. The Trust is a passive entity, and the Trustee has been given only such powers as are necessary for the collection and distribution of revenues from the Royalty Interest and the payment of Trust liabilities and expenses. The Trust has been formed under the Delaware Trust Act, which entitles holders of the Units of Beneficial Interest (the "Trust Units") to the same limitation of personal liability as stockholders of a corporation are afforded under Delaware law. The Trust Units evidence undivided interests in the Trust and are listed on the New York Stock Exchange under the ticker symbol "BPT".

The Trust Units are not an interest in or obligation of the Company, Standard Oil or BP. The ultimate value of the Royalty Interest will be dependent on the Royalty Production and the Per Barrel Royalty for each day. The "Per Barrel Royalty" for any day will equal the per barrel price of West Texas Intermediate crude oil, less scheduled chargeable costs, as adjusted, and production taxes. See "Description of the Royalty Interest." In certain circumstances, the Royalty Interest provided for a minimum royalty payment of $8.92 per barrel of Royalty Production, if any, from the PBU for each quarter through September 30, 1991; for all quarters thereafter there is no minimum royalty payment. Pursuant to a Support Agreement among BP, the Company, Standard Oil and the Trust, BP has guaranteed the performance by the Company of its payment obligations with respect to the Royalty Interest.

The only assets of the Trust are (i) the Royalty Interest assigned to the Trust and, (ii) from time to time, cash reserves and cash equivalents being held by the Trustee for distribution. Subject to compliance with certain conditions, additional royalty interests may be assigned to the Trust. See "Description of the Trust Units and the Trust Agreement- Additional Conveyances."

The value of the Trust Units is substantially dependent upon estimates of proved reserves, production and the value of oil. 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. See "Report of Miller and Lents, Ltd.", independent petroleum consultants, included herein.

The Company shares control of the operation of the PBU with the other working interest owners, and has no obligation to continue production from the PBU or to maintain production at any level and may interrupt or discontinue production at any time. In addition, the operation of the PBU is subject to normal operating hazards incident to the production and transportation of oil in Alaska. In the event of damage to the PBU which is covered by insurance, the Company has no obligation to use insurance proceeds to repair such damage and may elect to retain such proceeds and close damaged areas to production.

The financial statements of the Trust contained in this Annual Report on Form 10-K include information regarding amounts distributed to Trust Unit holders with respect to 1994, 1993, and 1992. This Annual Report also includes information with respect to 1994 production and production in past periods. Amounts distributed with respect to 1994, 1993, and 1992, production in 1994 and in the past, and the most recent estimates of proved reserves attributable to the Trust are not indicative of amounts to be distributed in the future.

The following information is subject to the detailed provisions of the Trust Agreement, the Overriding Conveyance, and the Trust Conveyance.

The provisions governing the Trust are complex and extensive, and no attempt has been made below to describe all of such provisions. The following is a general description of the basic framework of the Trust and reference is made to the Trust Agreement for detailed provisions concerning the Trust.

DESCRIPTION OF THE TRUST UNITS AND THE TRUST AGREEMENT

CREATION AND ORGANIZATION OF THE TRUST

The Trust holds the Royalty Interest pursuant to the terms of the Trust Agreement and the Conveyance, subject to the laws of the States of

Alaska and Delaware. The beneficial interest in the Trust created by the Trust Agreement is divided into equal undivided portions called Trust Units. See the discussion below under "Trust Units".

The Bank of New York (Delaware) has been appointed co-trustee in order to satisfy certain requirements of the Delaware Trust Act, but The Bank of New York alone is able to exercise the rights and powers granted to the Trustee in the Trust Agreement.

ASSETS OF THE TRUST

The Royalty Interest is the only asset of the Trust, other than cash being held for the payment of expenses and liabilities and for distribution to the holders of Trust Units. See "Duties and Limited Powers of Trustee".

LIABILITY OF THE TRUST

Because of the passive nature of the Trust's assets and the restrictions on the power of the Trustee to incur obligations, it is anticipated that the only liabilities the Trust will incur will be those for routine administrative expenses, such as Trustee's fees, and accounting, legal and other professional fees. However, if a court were to hold that the Trust is an association taxable as a corporation, as more fully discussed in "Certain Tax Considerations-Federal Income Tax- Classification of the Trust", the Trust would incur substantial income tax liabilities in addition to its other expenses. In addition, if the Trust were required to make allocations of income and deductions other than on a quarterly basis, the administrative expenses of the Trust might increase. See "Certain Tax Considerations-Federal Income Tax-Taxation of Trust Unit Holders". The administrative fees and expenses of the Trust for the years ended December 31, 1994, 1993, 1992, 1991, 1990 and 1989 were approximately $660,000, $555,000, $415,000, $415,000, $460,000 and $170,000, respectively, including fees paid by the Trust to accountants, petroleum consultants and counsel. Future administrative fees and expenses will depend, among other things, on the number of Trust Unit holders and the fees of accountants, petroleum consultants, counsel and other experts, if any, engaged by the Trust.

DUTIES AND LIMITED POWERS OF TRUSTEE

The duties of the Trustee are as specified in the Trust Agreement and by the laws of the State of Delaware. The basic function of the Trustee is to collect income from the Royalty Interest, to pay out of the Trust's income and assets all expenses, charges and obligations and to pay available cash to holders of Trust Units.

The Trustee may establish a cash reserve for the payment of material liabilities of the Trust which may become due, if the Trustee has determined that it is not practical to pay such liabilities on subsequent Quarterly Record Dates (as defined below) out of funds anticipated to be available on such dates and that, in the absence of such reserve, the trust

estate is subject to the risk of loss or diminution in value or The Bank of New York is subject to the risk of personal liability for such liabilities, provided that, except in certain limited circumstances, it has received an opinion of counsel to the effect that the establishment and maintenance of such reserve 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. The Trustee is obligated, subject to certain conditions, to borrow funds required to pay liabilities of the Trust, if they become due, and pledge or otherwise encumber the Trust's assets, if it determines that the cash on hand is insufficient to pay such liabilities and that it is not practical to pay such liabilities on subsequent Quarterly Record Dates out of funds anticipated to be available on such dates, provided that, except in certain limited circumstances, it has received an opinion of counsel to the effect described above. Borrowings must be repaid in full before any further distributions are made to holders of Trust Units.

All distributable cash of the Trust will be distributed on a quarterly basis. To date, and until certain requirements of the Trust Agreement are met concerning the status of the assets of the Trust for purposes of certain Department of Labor regulations, all distributions to Trust Unit holders must be made as soon as practicable and the Trustee must hold cash received uninvested pending such distribution. The Trustee is required to invest any cash being held by it for distribution on the next distribution date or being held by it as a reserve for liabilities in U.S. Obligations or, if U.S. Obligations having a maturity date on the next distribution date are not available, repurchase agreements with banks, including The Bank of New York, secured by U.S. Obligations and meeting certain specified requirements. Any U.S. Obligation or any such repurchase agreement must mature on the next distribution date or on the due date of the liability with respect to which the reserve is established, if known, and subject to certain exceptions, will be held to maturity. The Trustee is required, in certain circumstances, to invest the cash being held by it in an overnight time deposit with a bank, including The Bank of New York. Amounts being held by the Trustee after the date fixed for distribution of assets upon termination of the Trust, however, must be held uninvested.

The Trust Agreement grants the Trustee only such rights and powers as are necessary to achieve the purposes of the Trust. The Trust Agreement prohibits the Trust from engaging in any business, commercial or, with certain exceptions, investment activity of any kind and from using any portion of the assets of the Trust to acquire any oil and gas lease, royalty or other mineral interest. The Trustee may sell Trust properties only as authorized by a vote of the holders of Trust Units, or when necessary, to provide for the payment of specific liabilities of the Trust then due (if, among other things, the Trustee determines that it is not practicable to submit such sale to a vote of the holders of Trust Units, and it receives an opinion of counsel to the effect that such sale will not adversely affect the classification of the Trust as a "grantor trust" for federal income tax purposes), or upon termination of the Trust. Pledges or

other encumbrances to secure borrowings are permitted without a vote of holders of Trust Units if the Trustee determines such action is advisable. Any sale of Trust properties must be for cash unless otherwise authorized by the holders of Trust Units, and the Trustee is obligated to distribute the available net proceeds of any such sale to the holders of Trust Units after establishing reserves for liabilities of the Trust.

LIABILITIES OF TRUSTEE

Except in the circumstances described below, in which the Company will indemnify the Trustee and The Bank of New York in its individual capacity, the Trustee and The Bank of New York in its individual capacity will be indemnified out of the assets of the Trust for any liability, expense, claim, damage or other loss incurred by it in the performance of its duties unless such loss results from its negligence, bad faith, or fraud or from its expenses in carrying out such duties exceeding the compensation and reimbursement it is entitled to under the Trust Agreement. The Trustee and The Bank of New York in its individual capacity will be indemnified by the Company for liabilities to the extent described above (a) whenever the assets of the Trust are insufficient or not permitted by applicable law to provide such indemnity and (b) after the termination of the Trust, to the extent that the Trustee did not have knowledge or should not have reasonably known of a potential claim against the Trustee for which a reserve could have been established and used to satisfy such claim prior to the final distribution of assets of the Trust upon its termination. In no event will the Trustee be deemed to have acted negligently, fraudulently or in bad faith if it takes or suffers action in good faith in reliance upon and in accordance with the written advice of counsel or other experts.

The Trustee is not entitled to indemnification from the holders of Trust Units except in certain limited circumstances related to the replacement of mutilated, destroyed, lost or stolen certificates. In addition, the Company has agreed to indemnify and hold the Trustee and the Trust harmless from certain liabilities under the federal securities laws.

RESIGNATION OR REMOVAL OF TRUSTEE

The Trustee may resign at any time or be removed with or without cause by the holders of a majority of the outstanding Trust Units. Its successor must be a corporation organized and doing business under the laws of the United States, any state thereof or the District of Columbia authorized under such laws to exercise trust powers, 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 the State of Delaware, then any successor trustee will be such a resident or have such a principal office. No resignation or removal of the Trustee shall become effective until a successor trustee shall have accepted such appointment.

DURATION OF TRUST

The Trust is irrevocable and the Company has no power to terminate the

Trust or, except with respect to certain corrective amendments agreed to by the Trustee, to alter or amend the terms of the Trust Agreement. The Trust will terminate upon the first to occur of the following events or times: (a) upon a vote of holders of not less than 70% of the outstanding Trust Units, on or prior to December 31, 2010, in accordance with the procedures described under "Voting Rights of Holders of Trust Units" below, or (b) after December 31, 2010 either (i) at such time as the net revenues from the Royalty Interest for two successive years commencing after 2010 are less than $1,000,000 per year, unless the net revenues during such period have been materially and adversely affected by an event constituting force majeure, or (ii) upon a vote of holders of not less than 60% of the outstanding Trust Units. Upon the dissolution of the Trust, the Trustee will continue to act in such capacity until completion of the winding up of the affairs of the Trust. Upon termination of the Trust, the Trustee will sell Trust properties in one or more sales for cash, unless holders representing 70% of the Trust Units outstanding (60% if the decision to terminate the Trust is made after December 31, 2010) authorize the sale for a specified non-cash consideration in which event the Trustee may, but is not obligated to, consummate such non-cash sale, but only if the Trustee shall have received a ruling from the Internal Revenue Service (the "IRS") 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. Prior to such sale the Trustee will obtain an opinion of an investment banking firm or other entity qualified to give such opinion as to the fair market value of the assets of the Trust on the day of termination of the Trust. The Trustee will effect any such sale pursuant to procedures or material terms and conditions approved by the vote of holders of 70% of the outstanding Trust Units (60% if the sale is made after December 31, 2010) in accordance with the procedures described under "Voting Rights of Holders of Trust Units" below, unless the Trustee determines that it is not practicable to submit such procedures or terms to a vote of the holders of Trust Units, and the sale is effected at a price which is at least equal to the fair market value of the trust estate as set forth in the opinion mentioned above and pursuant to terms and conditions deemed commercially reasonable by the investment banking firm or other entity rendering such opinion. Upon dissolution of the Trust, the Company 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 estate as set forth in the opinion mentioned above, or (ii) the number of then outstanding Trust Units multiplied by (a) the closing price of Trust Units on the day of termination of the Trust on the stock exchange on which the Trust Units are listed, or (b) if the Trust 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 National Market System of the National Association of Securities Dealers Automated Quotation System. If the Trust Units are neither listed nor traded in the over-the-counter

market, the price will be the fair market value of the trust estate as set forth in the opinion mentioned above. After satisfying all existing liabilities and establishing adequate reserves for the payment of contingent liabilities, the Trustee will distribute all available proceeds to the holders of Trust Units on the date specified in a notice given by the Trustee, which date will be no later than 10 days after delivery of such notice.

The Trustee cannot predict what amount it will be able to receive for the Trust's assets if the Trust terminates or the expenses which the Trust may incur in attempting to sell the assets.

VOTING RIGHTS OF HOLDERS OF TRUST UNITS

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

Meetings of holders of Trust Units may be called by the Trustee at any time at its discretion and must be called by the Trustee at the written request of holders of not less than 25% of the then outstanding Trust Units or at the request of the Company or as may be required by law or applicable regulation. The presence of a majority of the outstanding Trust Units is necessary to constitute a quorum, and holders may vote in person or by proxy.

Notice of any meeting of holders of Trust Units must be given not more than 60 nor fewer than 10 days prior to the date of such meeting. The notice must state the purpose or purposes of the meeting and no other matter may be presented or acted upon at the meeting.

The Trust Agreement may be amended without a vote of the holders of Trust Units to cure an ambiguity, to correct or supplement any provision of the Trust Agreement that may be inconsistent with any other such provision or to make any other provision with respect to matters arising under the Trust Agreement that do not adversely affect the holders of Trust Units. The Trust Agreement may also be amended with the approval of a majority of the outstanding Trust Units at any duly called meeting of holders of Trust Units. However, no such amendment may alter the relative rights of Trust Unit holders unless approved by the affirmative vote of 100% of the holders of Trust Units and by the Trustee or reduce or delay the distributions to the holders of Trust Units or effect certain other changes unless approved by the affirmative vote of 80% of the holders of Trust Units and by the Trustee. No amendment will be effective until the Trustee has received a ruling from the IRS 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.

Removal of the Trustee will require the affirmative vote of the holders of a majority of the Trust Units represented at a duly called meeting of the holders of Trust Units. A successor trustee may be appointed by the holders of Trust Units at such meeting. If the Trustee has given notice of its intention to resign, a successor trustee will be appointed by the Company.

The sale of all or any part of the Royalty Interest must be authorized by the affirmative vote of the holders of 70% of the outstanding Trust Units (60% if such sale is to be effected after December 31, 2010), provided that if such sale is effected in order to provide for the payment of specific liabilities of the Trust then due and involves a part, but not all or substantially all, of the assets of the Trust, such sale may be approved by the affirmative vote of holders of a majority of the outstanding Trust Units. However, subject to certain conditions, the Trustee may, without a vote of the holders of Trust Units, sell all or any part of the Trust assets if necessary to provide for the payment of specific liabilities of the Trust then due or upon termination of the Trust. The Trust can be terminated by the holders of Trust Units only if the termination is approved by the holders of 70% of the Trust Units (on or prior to December 31, 2010) or of 60% of the Trust Units (after December 31, 2010). The Trust may also be terminated after December 31, 2010 if the net revenues from the Royalty Interest for two successive years commencing after 2010 are less than $1,000,000 per year, unless the net revenues have been materially and adversely affected by an event constituting force majeure.

The Company and Standard Oil will vote or cause to be voted any Trust Units held of record or beneficially by the Company, Standard Oil or any affiliate of either of them in the same proportion as the Trust Units voted by other holders of Trust Units at such meeting.

TRUST UNITS

Each Trust Unit represents an equal undivided share of beneficial interest in the Trust. Trust Units are evidenced by transferable certificates issued by the Trustee. If at any time there is assigned to the Trust an Additional Royalty Interest, the beneficial interest in the Trust will thereafter be considered to be divided into a number of Trust Units equal to the sum of the number of Trust Units existing prior to such assignment and the number of Trust Units created upon such assignment. The Trust Units will not represent an interest in or obligation of the Company, Standard Oil or any of their respective affiliates. Except in the limited circumstances described under "Additional Conveyances" each Trust Unit will entitle its holder to the same rights as the holder of any other Trust Unit, and the Trust will have no other authorized or outstanding class of equity securities. There are 21,400,000 Trust Units outstanding.

DISTRIBUTIONS OF INCOME

The Company will pay the Trust amounts due pursuant to the Royalty Interest on a quarterly basis on the fifteenth day after the end of each calendar quarter (or, if such day is not a business day, on the next succeeding business day) unless due to applicable law or stock exchange rules a different payment day is required. Distributions of Trust income are currently made as soon as practicable after receipt of such amounts by the Trustee. After certain requirements of the Trust Agreement concerning the status of the assets of the Trust under certain Department of Labor regulations are met, distributions of Trust income will be made on the fifth day (or if such day is not a business day, on the next succeeding business day) after the Trustee's receipt in same day finally collected funds of amounts to be received on a Quarterly Record Date for each Quarter (defined below) in each year during the term of the Trust. Such distribution will be made to the person in whose name the Trust Unit (or any predecessor Trust Unit) is registered at the close of business on the immediately preceding January 15, April 15, July 15, or October 15 (or, if such day is not a business day, on the next succeeding business day), as the case may be, unless the Trustee determines that a different date is required to comply with applicable law or stock exchange rules (each a "Quarterly Record Date"). A "Quarter", for purposes of the Trust Agreement, is a period of approximately three months beginning on the day after a Quarterly Record Date and continuing through and including the next succeeding Quarterly Record Date. The aggregate quarterly distribution of income (the "Quarterly Income Amount") will be the excess of (i) revenues from the Royalty Interest plus any decrease in cash reserves previously established for estimated liabilities and any other cash receipts of the Trust over (ii) the expenses and payments of liabilities of the Trust plus any net increase in cash reserves for estimated liabilities. If prior to the end of a Quarter the Trustee makes a determination of the Quarterly Income Amount which it anticipates will be distributed to holders of Trust Units on the Quarterly Record Date for such Quarter, based on notice provided to the Trustee by the Company, and the Quarterly Income Amount is not equal to the amount so determined due to late payment, the Trustee will treat such amounts when received as if they were received on such Quarterly Record Date. Payment of the respective pro rata portion of the aggregate quarterly distribution of income to each holder of Trust Units will be made by check mailed to each such holder, provided that holders of Trust Units may arrange for payments of $100,000 or more to be made by wire transfer in immediately available funds.

TRANSFERS

The Trustee acts as registrar and transfer agent for the Trust Units. Subject to the limitations set forth below and to the limitation described under "Additional Conveyances" below, Trust Units may be transferred by surrender of the certificates duly endorsed, or accompanied by a written instrument of transfer, in form satisfactory to the Trustee, duly executed by the holder of the Trust Unit or his attorney duly authorized in writing. No service charge will be made for any registration of transfer of Trust

Units, but the Trustee may require the payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in connection with any registration of transfer. Until a transfer is made in accordance with the regulations prescribed by the Trustee, the Trustee may conclusively treat as the owner of any Trust Unit, for all purposes, the holder shown by its records (except in the event of a purchase by the Company or a designee thereof of Trust Units subject to the Trustee's right of redemption, as described under "Possible Divestiture of Trust Units" below). Any transfer of a Trust Unit will vest in the transferee all rights of the transferor at the date of transfer, except that the transfer of a Trust Unit after the Quarterly Record Date for distribution will not transfer the right of the transferor to such distribution. The Trustee is specifically authorized to rely upon the application of Article 8 of the Uniform Commercial Code, the Uniform Act for Simplification of Fiduciary Security Transfers and other statutes and rules with respect to the transfer of securities, each as adopted and then in force in the State of Delaware, as to all matters affecting title, ownership, warranty or transfer of certificates and the Trust Units represented thereby.

MUTILATED, DESTROYED, LOST OR STOLEN CERTIFICATES

If a mutilated certificate is surrendered to the Trustee, the Trustee will execute and deliver in exchange therefor a new certificate. If there shall be delivered to the Trustee evidence of the destruction, loss or theft of a certificate and such security or indemnity as may be required to hold the Trust and the Trustee harmless, then, in the absence of notice to the Trustee that such certificate has been acquired by a bona fide purchaser, the Trustee will execute and deliver, in lieu of any such lost, stolen or destroyed certificate, a new certificate. In connection with the issuance of any new certificates, the Trustee may require the payment of a sum sufficient to cover any tax or other governmental charge that may be imposed in relation thereto and any other expenses (including fees and expenses of the Trustee) in connection therewith.

REPORTS TO HOLDERS OF TRUST UNITS

As promptly as practicable following the end of each calendar year, but no later than 90 days thereafter, the Trustee will mail to each person who was a holder of record at any time during such calendar year a report containing sufficient information to enable holders of Trust Units to make all 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 such calendar year. As promptly as practicable following the end of each Quarter, but no later than 60 days following the end of such Quarter, during the term of the Trust, the Trustee will mail a report for such Quarter showing in reasonable detail on a cash basis the assets and liabilities, receipts and disbursements and income and expenses of the Trust and the Royalty Production for such Quarter to holders of Trust Units of record on the last Quarterly Record Date immediately preceding the mailing thereof. Within 90 days following the end of each calendar year, the Trustee will mail an annual report containing (a)

audited financial statements of the Trust, (b) a statement as to whether or not all fees and expenses of the Trustee were calculated and paid in accordance with the Trust Agreement, (c) such information as the Trustee deems appropriate from a letter of the independent public accountants engaged by the Trustee as to compliance with certain terms of the Conveyance and any Additional Conveyances and computation of the amounts payable to the Trust in respect of the Royalty Interest, (d) a letter of the independent petroleum engineers engaged by the Trust setting forth a summary of such firm's determinations regarding the Company's methods, procedures and estimates referred to in the Conveyance concerning proved reserves and other related matters, and (e) a copy of the latest annual report with respect to the Trust Units filed with the Securities and Exchange Commission (the "Commission") or information furnished to the Trustee pursuant to the Conveyance, to holders of Trust Units of record on the last Quarterly Record Date immediately preceding the mailing thereof.

The Trustee will mail to holders of Trust Units any other reports or statements required to be provided to Trust Unit holders by applicable law or governmental regulations or by the requirements of any stock exchange on which the Trust Units may be listed.

In the Trust Agreement, holders of Trust Units have waived the right to seek or secure any portion 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.

LIABILITY OF HOLDERS OF TRUST UNITS

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

POSSIBLE DIVESTITURE OF TRUST UNITS

The Trust Agreement imposes no restrictions on nationality or other status of the persons or other entities which are eligible to hold Trust Units. However, the Trust Agreement 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 holders the following procedures will be applicable:

(i) The Trustee will give written notice of the existence of such proceedings to each holder whose nationality or other status is an issue in the proceeding. The notice will contain a reasonable summary of such proceeding and will constitute a demand to each such holder that he dispose of his Trust Units within 30 days to a party not of the nationality or other status at issue in the proceeding described in the notice.

(ii) If any holder fails to dispose of his Trust Units in accordance with such notice, the Trustee shall have the right to redeem and shall redeem at any time during the 90-day period following the termination of the 30-day period specified in the notice, any Trust Unit not so transferred for a cash price per unit equal to the closing price of the Trust Units on the stock exchange on which the Trust Units are then listed or, in the absence of any such listing, the closing bid price on the National Market System of the National Association of Securities Dealers Automatic Quotation System if the Trust Units are so quoted or, if not, the mean between the closing bid and asked prices for the Trust Units in the over-the-counter market, in either case as of the last business day prior to the expiration of the 30-day period stated in the notice. If the Trust Units are neither listed nor traded in the over-the-counter market, the price will be the fair market value of the Trust Units as determined by a recognized firm of investment bankers or other competent advisor or expert.

(iii) The Trustee will cancel any Trust Unit redeemed by the Trustee in accordance with the foregoing procedures.

(iv) The Trustee may, in its sole discretion, cause the Trust to borrow any amount required to redeem the Trust Units.

If the purchase of Trust Units from an ineligible holder by the Trustee would result in a non-exempt "prohibited transaction" under the Employee Retirement Income Security Act of 1974, as amended ("ERISA"), or under the Internal Revenue Code of 1986, as amended (the "Code"), the Trust Units subject to the Trustee's right of redemption will be purchased by the Company or a designee thereof, at the above-described purchase price.

ADDITIONAL CONVEYANCES

Additional royalty interests ("Additional Royalty Interests") identical in all respects to the initial Royalty Interest except for the identity of the parties (other than the Trust) (provided that the entity which will make payments to the Trust under any Additional Royalty Interest is the same entity making payments to the Trust under the initial Conveyance), the effective date (which must be on the first day of a calendar quarter and must be the date of delivery thereof to the Trustee) and the percentage set forth in the definition of Royalty Production in the related additional conveyance, may be assigned by the Company or an affiliate thereof to the Trust from time to time, through the execution of additional conveyances (each an "Additional Conveyance"). In consideration of the grant of an Additional Royalty Interest, the Trustee will issue to the order of the Company or such affiliate, a number of Trust Units, not to exceed a total of 18,600,000 additional Trust Units, equal to (i) the product of (a) the percentage set forth in the definition of "Royalty Production" in the related Additional Conveyance and (b) 21,400,000, (ii) divided by 16.4246%. In connection with such issuance, the recipients of such Trust Units and their transferees will not be treated as holders of Trust Units of record entitled to distributions with respect to the Quarterly Income Amount for the Quarterly Record Date which occurs during

the month in which such Additional Conveyance is effective and will not be entitled to transfer such Trust Units (other than to the Company or one of its affiliates) on or prior to such Quarterly Record Date, and the certificates representing such Trust Units will prominently so state.

The acceptance by the Trustee of any such assignment will be subject to the conditions that the Trustee shall have received a ruling from the IRS to the effect that neither the existence nor the exercise of the right to assign the Additional Royalty Interest or the power to accept such assignment will adversely affect the classification of the Trust as a "grantor trust" for federal income tax purposes, and rulings from the IRS or an opinion of counsel to the effect that such assignment will not cause the income from the Trust to be treated as unrelated business taxable income for federal income tax purposes, or the holders of Trust Units to recognize income, gain or loss attributable to the Royalty Interest as a result of such assignment, except to the extent of any gain or loss attributable to any cash received by the Trust in connection with such assignment.

In addition, the Trustee will require that the Company or its affiliate contribute a cash reserve computed by reference to the value of the cash reserve for future liabilities existing on the date the Additional Conveyance is effective. The Trustee will invest any cash so contributed as described under "Duties and Limited Powers of Trustee" above, and will distribute the cash so contributed and any interest earned thereon to holders of Trust Units of record on the Quarterly Record Date which occurs during the month in which the related Additional Conveyance becomes effective, except to holders of Trust Units issued upon the assignment of the Additional Conveyance.

Any Additional Royalty Interest assigned to the Trust will constitute a part of the trust estate and, to the extent permitted by law, will be treated by the Trustee, together with the initial Royalty Interest and all other Additional Royalty Interests previously assigned to the Trust, as constituting one Royalty Interest held for the benefit of all holders of Trust Units.

DESCRIPTION OF THE ROYALTY INTEREST

The Trust property consists of a Royalty Interest entitling the Trust to a Per Barrel Royalty on 16.4246% of the first 90,000 barrels of the average actual daily net production of oil and condensate per quarter (the "Royalty Production") from the Company's working interest in the PBU. There are 21,400,000 Trust Units outstanding. If additional Trust Units are issued, the Royalty Interest percentage will be increased proportionately. The net production referred to herein 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 Company's average daily net production from its working interest in the PBU during 1994 was approximately 369,900 barrels of oil and condensate.

As is true of net profits royalty interests generally, the Royalty Interest is a property right under applicable principles of Alaska law which burdens production, but there is no other security interest in the reserves or production revenues to which the Royalty Interest is entitled.

The royalty payable to the Trust under the Royalty Interest is the product of the Royalty Production and the Per Barrel Royalty for each day.

PER BARREL ROYALTY

The Per Barrel Royalty in effect for any day will equal the WTI Price for such day less the sum of (i) the product of the Chargeable Costs and the Cost Adjustment Factor and (ii) Production Taxes.

WTI PRICE

The "WTI Price" for any trading day means (i) the latest price (expressed in dollars per barrel) for West Texas Intermediate crude oil of standard quality having a specific gravity of 40 degrees API for delivery at Cushing, Oklahoma ("West Texas Crude"), quoted for such trading day by the Dow Jones International Petroleum Report (which is published in The Wall Street Journal) or if the Dow Jones International Petroleum Report does not publish such quotes, then such price as quoted by Reuters, or if Reuters does not publish such quotes, then such price as quoted in Platt's Oilgram Price Report, or (ii) if for any reason such publications do not publish such price, then the WTI Price will mean, until (i) is again applicable, the simple average of the daily mean prices (expressed in dollars per barrel) quoted for West Texas Crude by one major oil company, one petroleum broker and petroleum trading company, in each case unaffiliated with

BP. Such major oil company, petroleum broker and petroleum trading company must have substantial U.S. operations and will be designated by the Company from time to time in an officer's certificate delivered to the Trustee. In the event that prices for West Texas Crude are not quoted so as to permit the calculation of the WTI Price, "West Texas Crude," for the purposes of calculating the WTI Price first for (i) and then (ii) above, will mean such other light sweet domestic crude oil of standard quality as is designated by the Company in an officer's certificate delivered to the Trustee and approved by the Trustee in the exercise of its reasonable judgment, with appropriate allowance for transportation costs to the Gulf Coast (or other appropriate location) to equilibrate such price to the WTI Price. The WTI Price for any day which is not a trading day will be the WTI Price for the next preceding day which is a trading day.

CHARGEABLE COSTS

The "Chargeable Costs" per barrel of Royalty Production were $4.50 per barrel through December 31, 1991, $6.00 per barrel from January 1, 1992 through December 31, 1992, $6.75 per barrel from January 1, 1993 through December 31, 1993, $8.00 per barrel from January 1, 1994 through

December 31, 1994 and will be the amount set forth in the following table opposite the calendar year stated:

For the Year Ending December 31,	Chargeable Costs Per Barrel	For the Year Ending December 31,	Chargeable Costs Per Barrel
1995	$8.25	2008	$13.00
1996	8.50	2009	13.25
1997	8.85	2010	14.50
1998	9.30	2011	16.60
1999	9.80	2012	16.70
2000	10.00	2013	16.80
2001	10.75	2014	16.90
2002	11.25	2015	17.00
2003	11.75	2016	17.10
2004	12.00	2017	17.20
2005	12.25	2018	20.00
2006	12.50	2019	23.75
2007	12.75	2020 and thereafter	26.50 increasing by $2.75 each year thereafter

Chargeable Costs are multiplied by the Cost Adjustment Factor as defined below.

Chargeable Costs will be reduced up to a maximum of $1.20 per barrel in any given year subsequent to 1995 based on the following tests of the Company's additions of Proved Reserves to Current Reserves. Current Reserves are defined as the Company's Proved Reserves of crude oil and condensate as of December 31, 1987 (2035.6 million stock tank barrels ("STB")) and before taking into account any production therefrom and before any reduction that may result from the creation of the Trust.

(a) If, by December 31, 1995, 100,000,000 or more STB of Proved Reserves have not been added to Current Reserves, then for each year 1996 through 2000, inclusive, Chargeable Costs as set forth in the table above shall be reduced, as of January 1 in each such year, by an amount equal to the lesser of (A) $1.20 or (B) the product of $1.20 and a fraction, the numerator of which shall be the difference between 100,000,000 STB of Proved Reserves and the actual number of STB of Proved Reserves so added to Current Reserves from January 1, 1988 through December 31, 1995 and the denominator of which shall be 100,000,000 STB of Proved Reserves. The Company added approximately 42,000,000 STB to Proved Reserves during 1988, approximately 45,500,000 STB during 1989, approximately

24,000,000 STB during 1990, approximately 116,000,000 STB during 1991, approximately 144,000,000 STB during 1992, approximately 206,000,000 STB during 1993 and approximately 90,000,000 STB during 1994.

(b) If between January 1, 1996 and December 31, 2000 an additional 200,000,000 STB of Proved Reserves (that is, 200,000,000 STB of Proved Reserves in addition to the 100,000,000 STB of Proved Reserves that are referred to in (a)) have not been added to Current Reserves, then for each year from 2001 through 2005, inclusive, Chargeable Costs as set forth in the table above shall be reduced, as of January 1 in each such year, by an amount equal to the lesser of (A) $1.20 or (B) the product of $1.20 and a fraction, the numerator of which shall be the difference between (1) 200,000,000 STB of Proved Reserves and (2) the sum of (i) the actual number of STB of Proved Reserves so added to Current Reserves from January 1, 1996 through December 31, 2000 plus (ii) the excess, if any, of the number of STB of Proved Reserves so added to Current Reserves from January 1, 1988 through December 31, 1995 over 100,000,000 STB of Proved Reserves (provided that the sum of (i) and (ii) shall not exceed 200,000,000 STB of Proved Reserves) and the denominator of which shall be 200,000,000 STB of Proved Reserves.

(c) The tests set forth in (i) and (ii) below will be utilized to calculate the reduction, if any, in Chargeable Costs for the year 2006 and each year thereafter. If the calculation under one of such tests produces a reduction in Chargeable Costs but the calculation under the other test does not, the calculation that produces the reduction shall apply. In applying the tests below, it is the intention of the Company that test (i) allow as a credit toward the 400,000,000 STB of Proved Reserves that must be added to Current Reserves during the period set forth in such test an amount equal to the excess, if any, of the number of STB of Proved Reserves added to Current Reserves prior to December 31, 2000 over 300,000,000 STB of Proved Reserves while test (ii) sets a level of only 100,000,000 STB of Proved Reserves that must be added to Current Reserves during the period set forth in such test, but does not allow a credit for additions of STB of Proved Reserves accrued prior to December 31, 2000.

(i) If, between January 1, 2001 and December 31, 2005, an additional 400,000,000 STB of Proved Reserves (that is, 400,000,000 STB of Proved Reserves in addition to the 100,000,000 STB of Proved Reserves that are referred to in (a) and the 200,000,000 STB of Proved Reserves that are referred to in (b)) have not been added to Current Reserves, then for the year 2006 and each year thereafter Chargeable Costs as set forth in the table above shall be reduced, as of January 1 of each such year, by an amount equal to the lesser of (A) $1.20 or (B) the product of $1.20 and a fraction, the numerator of which shall be the difference between (1) 400,000,000 STB of Proved Reserves and (2) the sum of (x) the actual number of STB of Proved Reserves so added to Current Reserves from January 1, 2001 through December 31, 2010 plus (y) the excess, if any, of the number of STB of Proved Reserves so added to Current Reserves from January 1, 1988 through December 31, 2000 over 300,000,000 STB of Proved Reserves (provided that the sum of (x) and (y) shall not exceed 400,000,000 STB of Proved Reserves) and the denominator of which shall be 400,000,000 STB of Proved Reserves.

(ii) If, between January 1, 2001 and December 31, 2005, an additional 100,000,000 STB of Proved Reserves (that is, 100,000,000 STB of Proved Reserves in addition to any and all STB of Proved Reserves that are added to Current Reserves prior to January 1, 2001) have not been added to Current Reserves, then for the year 2006 and each year thereafter, Chargeable Costs as set forth in the table above shall be reduced, as of January 1 of each such year, by an amount equal to the lesser of (A) $1.20 or (B) the product of $1.20 and a fraction, the numerator of which shall be the difference between 100,000,000 STB of Proved Reserves and the number of STB of Proved Reserves added to Current Reserves from January 1, 2001 through December 31, 2005 and the denominator of which shall be 100,000,000 STB of Proved Reserves.

COST ADJUSTMENT FACTOR

The "Cost Adjustment Factor" is the ratio of (1) the Consumer Price Index ("CPI") published for the most recently past February, May, August or November, as the case may be, to (2)121.1 (the Consumer Price Index for January 1989); provided, however, that (a) if for any calendar quarter the average WTI Price is $18.00 or less, then in such event the Cost Adjustment Factor for such quarter shall be the Cost Adjustment Factor for the immediately preceding quarter, and (b) the Cost Adjustment Factor for any calendar quarter in which the average WTI Price exceeds $18.00, after a calendar quarter during which the average WTI Price is equal to or less than $18.00, and for each following calendar quarter in which the average WTI Price is greater than $18.00, shall be the product of (x) the Cost Adjustment Factor for the most recently past calendar quarter in which the average WTI Price is equal to or less than $18.00 and (y) a fraction, the numerator of which shall be the Consumer Price Index published for the most recently past February, May, August or November, as the case may be, and the denominator of which shall be the Consumer Price Index published for the most recently past February, May, August or November during a quarter in which the average WTI Price is equal to or less than $18.00. 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 by such Bureau.

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. For this purpose, such taxes will be computed at defined statutory rates. In the case of taxes based upon wellhead or field value, the Overriding Conveyance provides that the WTI Price less the product of $4.50 and the Cost Adjustment factor will be deemed to be the wellhead or field value. At the present time, the

Production Taxes payable with respect to the Royalty Production are the Alaska Oil and Gas Properties Production Tax ("Alaska Production Tax") and the Alaska Oil and Gas Conservation Tax ("Alaska Conservation Tax"). For the purposes of the Royalty Interest, the Alaska Production Tax will be computed without regard to the "economic limit factor", if any, as the greater of the "percentage of value amount" (based on the statutory rate and the wellhead value as defined above) and the "cents per barrel amount" as such terms are used with respect to such tax. As of the date of this report, the statutory rate for the purpose of calculating the "percentage of value amount" is 15%, and the Alaska Conservation Tax is a tax of $0.004 per barrel of net production. A surcharge to the Alaska Production Tax increased Production Taxes by $0.05 per barrel of net production effective July 1, 1989. However, beginning with the second calendar quarter (April- June) of 1995, $0.02 per barrel of this surcharge will be suspended because the State spill response fund will have reached $50 million. In the event the balance of that fund falls below $50 million, the $0.02 per barrel will be reinstated until the fund balance again reaches $50 million. The remaining $0.03 per barrel is not effected by the fund's balance and will continue to be imposed at all times.

ROYALTY PRODUCTION

The Royalty Production for each day in a calendar quarter will be 16.4246% of the first 90,000 barrels of the average of the Company's actual daily net production of oil and condensate for such quarter as produced from the company's oil rim and gas cap participation as of February 28, 1989 or as modified thereafter by any redetermination provided under the terms of the Prudhoe Bay Unit Operating Agreement and the Prudhoe Bay Unit Agreement. The Royalty Production will be based upon oil produced from the oil rim and condensate produced from the gas cap, but not upon gas production or natural gas liquids production. The Company's actual average daily net production of oil and condensate for any calendar quarter will be the total production of oil and condensate for such quarter, net of the State of Alaska royalty, divided by the number of days in such quarter.

CALCULATION OF ROYALTY AMOUNT

The Royalty Interest for each calendar quarter is the sum of the product of each day in such quarter of (i) the Royalty Production and (ii) the Per Barrel Royalty; provided that the payment under the Royalty Interest for any calendar quarter will not be (1) less than zero or (2) more than the aggregate value of the total production of oil and condensate from the Company's current working interest in the PBU for such calendar quarter, net of the State of Alaska royalty and less the value of any applicable payments made to affiliates of the Company.

MINIMUM ROYALTY

The Royalty Interest provided for a Minimum Per Barrel Royalty for the period from February 28, 1989 to September 30, 1991 of $8.92 per barrel (the "Minimum Per Barrel Royalty"); for all periods thereafter there is no Minimum Per Barrel Royalty.

The "Average Per Barrel Royalty" for each of the first three calendar quarters of 1991 was the average of the Per Barrel Royalty for each of the days in such quarter and in the three preceding quarters. During 1989, 1990, and 1991 through and including October 15, 1991, the Trust's distributions were based on the Average Per Barrel Royalty and not on the Minimum Per Barrel Royalty.

POTENTIAL CONFLICTS OF INTEREST BETWEEN THE COMPANY AND TRUST

The interests of the Company and the Trust with respect to the PBU could at times be different. In particular, because the Per Barrel Royalty will be based on the WTI Price and Chargeable Costs rather than the Company's actual price realized and actual costs, the actual per barrel profit received by the Company on the Royalty Production could differ from the Per Barrel Royalty to be paid to the Trust. It is possible, for example, that the relationship between the Company's actual per barrel revenues and costs could be such that the Company may determine to interrupt or discontinue production in whole or in part even though a Per Barrel Royalty may otherwise have been payable to the Trust pursuant to the Royalty Interest. This potential conflict of interest could affect the royalties paid to Trust Unit holders, although the Company will be subject to the terms of the Prudhoe Bay Unit Operating Agreement.

Holders of Trust Units will have certain voting rights with respect to the administration of the Trust, but will have no voting rights with respect to, and no control over, any operating matters related to the PBU. The Company will retain the sole right to control all matters relating to its working interest in the PBU, subject to the terms of the Prudhoe Bay Unit Operating Agreement.

DESCRIPTION OF THE BP SUPPORT AGREEMENT

BP has agreed pursuant to the terms of a Support Agreement, dated February 28, 1989, among BP, the Company, Standard Oil and the Trust (the "Support Agreement"), to provide financial support to the Company in meeting its payment obligations under the Royalty Interest.

Within 30 days of notice to BP pursuant to Article XI of the Trust Agreement, BP will ensure that the Company is in a position to perform its payment obligations under the Royalty Interest and to satisfy its payment obligations to the Trust under the Trust Agreement (including, without limitation, the obligation to make payments as indemnification), including, without limitation, contributing to the Company such funds as are necessary

to make such payments. BP's obligations under the Support Agreement are unconditional and directly enforceable by Trust Unit holders.

Except as described below, no assignment, sale, transfer, conveyance, mortgage or pledge or other disposition of the Royalty Interest will relieve BP of its obligations under the Support Agreement.

Neither BP nor the Company may transfer or assign its rights or obligations under the Support Agreement without the prior written consent of the Trust, except that BP can arrange for its obligations under the Support Agreement to be performed by any affiliate of BP, provided that BP remains responsible for ensuring that such obligations are performed in a timely manner.

The Company may sell or transfer all or part of its working interest in the PBU, although such a transfer will not relieve BP of its responsibility to ensure that the Company'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 the Company's working interest in the PBU if the transferee is of Equivalent Financial Standing and unconditionally agrees to assume and be bound by BP's obligation under the Support Agreement in a writing in form and substance reasonably satisfactory to the Trustee. A transferee of "Equivalent Financial Standing" is defined in the Support Agreement as an entity having a rating assigned to outstanding unsecured, unsupported long term debt from Moody's Investors Service of at least A3 or from Standard & Poor's Corporation of at least A- or an equivalent rating from at least one nationally-recognized statistical rating organization (after giving effect to the sale or transfer to such entity of all or substantially all of the Company's working interest in the PBU and the assumption by such entity of all of the Company's obligations under the Conveyance and of all BP's obligations under the Support Agreement).

DESCRIPTION OF THE PROPERTY

BACKGROUND

The Prudhoe Bay field (the "Field") is located on the North Slope of Alaska, 250 miles north of the Arctic Circle and 650 miles north of Anchorage. The Field extends approximately 12 miles by 27 miles and contains nearly 150,000 productive acres. The Field, which was discovered in 1968 by BP and others, has been in production since 1977 and during 1989, 1990, 1991, 1992, 1993 and 1994, produced on average 1.4 million, 1.3 million, 1.3 million, 1.2 million, 1.1 million and 1 million barrels of oil and condensate per day, respectively. The Field is the largest producing field in North America. As of January 1, 1995, approximately 8.64 billion STB of oil and condensate had been produced from the Field. The Company estimates that production will decline at an average rate of approximately

10% per year. Field development is well advanced with approximately $16.3 billion gross capital spent and a total of about 1,227 wells drilled. Other large fields located in the same area include the Kuparuk, Endicott, and Lisburne fields. Production from those fields is not included in the Royalty Interest.

Since several oil companies hold acreage within the Field, the PBU was established to optimize Field development. The Prudhoe Bay Unit Operating Agreement specifies the allocation of production and costs to PBU owners. The Company and a subsidiary of the Atlantic Richfield Company ("Arco") are the two Field operators. Other Field owners include affiliates of Exxon Corporation ("Exxon"), Mobil Corporation ("Mobil"), Phillips Petroleum Company ("Phillips") and Chevron Corporation ("Chevron").

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 (collectively, "PESS") formations. Underlying the Sadlerochit Group are the oil-bearing Lisburne and Endicott formations. The net production referred to herein pertains only to the Ivishak and PESS formations, collectively known as the Prudhoe Bay (PermoTriassic) Reservoir, and does not pertain to the Lisburne and Endicott formations.

The Ivishak sandstone was deposited some 250 million years ago during the Permian and Triassic geologic ages. The sediments in the Ivishak are composed of sandstones, conglomerate and shales which were deposited by a massive braided river/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/tar overlays the oil-water contact in the main field and has an average thickness of around 40 feet.

HYDROCARBONS IN PLACE

The reservoir contained approximately 22 billion STB of original oil in place, of which approximately 19 billion STB were in the light oil column. The light oil in the reservoir is a medium grade, low sulfur crude with an average specific gravity of 27 degrees API.

Original gas in place was approximately 46 trillion standard cubic feet ("TSCF") (equivalent to approximately 8 billion barrels of oil on a BTU basis), with 30 TSCF in the gas cap and 16 TSCF solution gas. The gas cap gas has an average specific gravity of 0.85 and is composed of 70 to

80% methane, 10 to 20% carbon dioxide and the remainder ethane and heavier components. The gas cap composition is such that, upon surfacing, a liquid hydrocarbon phase, known as condensate, is formed.

The interests of the Trust Unit holders are based upon oil produced from the oil rim and condensate produced from the gas cap, but not upon gas production (which is currently uneconomic) or natural gas liquids production stripped from gas produced.

PRUDHOE BAY UNIT OPERATION AND OWNERSHIP

Since several companies hold acreage within the Field's limits, a unit was established to ensure optimum development of the Field. The Prudhoe Bay Unit, which became effective on April 1, 1977, divided the Field into two operating areas. The Company is the operator of the Western Operating Area ("WOA") and Arco Alaska Inc. is the operator of the Eastern Operating Area ("EOA"). Oil and condensate production comes from both the WOA and EOA.

The Prudhoe Bay Unit Operating Agreement specifies the allocation of production and costs to the working interest owners. The Prudhoe Bay Unit Operating Agreement also defines operator responsibilities and voting requirements and is unusual in its establishment of separate participating areas for the gas cap and oil rim.

The Prudhoe Bay Unit ownership by participating area is summarized in the following table:

PRUDHOE BAY UNIT
OWNERSHIP BY PARTICIPATING AREA
(AS OF JANUARY 1, 1995)

	OIL RIM	GAS CAP
BP	50.68%	13.84%
Arco	21.78	42.56
Exxon	21.78	42.56
Mobil/Philips/Chevron ("MPC")	4.44	1.04
Others	1.32	0.00

Total	100.00%	100.00%
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OIL RIM REDETERMINATION

The Prudhoe Bay Unit Operating Agreement, which was entered into in 1977, required a final redetermination of participating interests in the oil rim, based upon improved technical knowledge of the reservoir as a result of Field operations. In 1982, the Company, Arco and Exxon (the three major interest owners holding a total of approximately 94% of the oil

rim) reached an agreement regarding final redetermination of participating interests in the Field.

In October 1982, Exxon initiated arbitration proceedings regarding final redetermination of participating interests in the oil rim. As a result of the arbitration proceedings, which were concluded in 1985, the Company's participating interest in the oil reservoir was 50.68%. At the current maximum allowable production rate, this resulted in the Company's interest becoming 655,200 net barrels of oil per day ("BOPD"). Also to adjust its share of cumulative total production since the inception of commercial production, the Company overlifted about 13,500 net BOPD for a two-year period ending in August, 1987. After the arbitration award, MPC challenged the award through litigation. Mobil, Phillips and Chevron agreed in principle in October 1990 to end their challenge to the 1985 arbitration on their participating area interest in exchange for a cash settlement from BP, ARCO and Exxon. This settlement became effective on completion of a definitive binding agreement between all PBU owners, known as the Issues Resolution Agreement ("IRA").

The Company has advised the Trustee that the IRA addresses, among other things, final determination of the Original Condensate Reserve ("OCR"), agreement on allocation of the OCR over time, agreement on an additional gas handling expansion project (GHX-2), extension of an existing Enhanced Oil Recovery ("EOR") project to the end of field life and the establishment of a plan of additional development.

The IRA is an agreement among the owners of the Prudhoe Bay Unit which is designed to promote cooperation, reduce conflicts, increase efficiency of operations, and resolve a number of issues that were previously subject to negotiation, arbitration, or litigation among the Unit owners. The Company has advised that final approval of the IRA has now been obtained from all Unit owners.

The Company has further advised that the OCR was finally determined to be 1,175 million stock tank barrels ("STB") for the Prudhoe Bay Unit, and that this OCR determination resulted in a reallocation of approximately 500 million STB of crude oil reserves to condensate reserves, for the Prudhoe Bay Unit. The Company has also advised that because BP owns 50.68% of the crude oil and 13.84% of the condensate, this OCR settlement alone results in a BP net reserve reduction. The Company has advised the Trustee, however, that the establishment of the OCR at this level when combined with the other elements of the agreement described above should result in no significant change to BP's net reserves, and that the changes agreed to by the Prudhoe Bay Unit owners, including the attendant increased production, are expected to have limited impact on the point at which the company's net production of oil and condensate would fall below 90,000 barrels per day.

PRODUCTION AND RESERVES

Production began on June 19, 1977, with the completion of the Trans Alaska Pipeline System ("TAPS"). Initially 750,000 BOPD was the TAPS limit, but after start-up, pipeline capacity was increased and in November 1979 a production rate of 1.5 million BOPD was achieved.

As of January 1, 1995, there were about 995 producing oil wells, 35 gas reinjection wells, 55 water injection wells and 117 water and miscible gas injection wells in the Field. In terms of individual well performance, oil production rates range from 100 to 6,500 BOPD. Currently, the average well production rate is about 965 BOPD.

The Company's share of the hydrocarbon liquids production from the Field includes oil, condensate and natural gas liquids. Using the production allocation procedures from the Prudhoe Bay Unit Operating Agreement, the Field's production and the Company's 1994 share of oil and condensate (net of State of Alaska royalty) was as follows:

PRUDHOE BAY UNIT
1994 PRODUCTION
(BARRELS PER DAY)

	Field	Company Net Share
Oil	785,545	348,384
Condensate	177,450	21,489
Total	962,995	369,873

The Company's net proved remaining reserves of oil and condensate in the PBU as of December 31, 1994 were 1,395,000,000 STB. This current estimate of reserves is based upon various assumptions, including a reasonable estimate of the allocation of hydrocarbon liquids between oil and condensate pursuant to the procedures of the Prudhoe Bay Unit Operating Agreement. The Company anticipates that its net production from its current proved reserves will exceed 90,000 barrels per day until the year 2014. The Company also projects continued economic production thereafter, at a declining rate, until the year 2030; however, for the economic conditions and reserve estimates as of December 31, 1994 the Per Barrel Royalty will be zero following the year 2009. For years subsequent to 1995, Chargeable Costs will be reduced up to a maximum amount of $1.20 per barrel in each year if additions of Proved Reserves to Current Reserves (as defined in CHARGEABLE COSTS) do not meet certain specific levels (see CHARGEABLE COSTS). The Company has added and anticipates adding to its proved reserves. Even if expected reservoir performance does not change, the estimated reserves, economic life, and future revenues attributable to the BP Prudhoe Bay Royalty Trust may change significantly in the future. This may result from changes in the West Texas Intermediate Price or from

changes in other prescribed variables utilized in calculations defined by the Overriding Royalty Conveyance. See Report of Miller and Lents, Ltd., Independent Petroleum Consultants, below.

MILLER AND LENTS, LTD.
OIL AND GAS CONSULTANTS

TWENTY-SEVENTH FLOOR
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February 28, 1995

The Bank of New York

Trustee, BP Prudhoe Bay Royalty Trust
101 Barclay Street 21 W
New York, New York 10286

Re: Estimates of Proved Reserves,
Future Production Rates, and
Future Net Revenues for the
BP Prudhoe Bay Royalty Trust
As of December 31, 1994

Gentlemen:

This letter report is a summary of investigations performed in accordance with our engagement by you as described in Section 4.8(d) of the Overriding Royalty Conveyance dated February 27, 1989, between BP Exploration (Alaska) Inc., and The Standard Oil Company. The investigations included reviews of the estimates of Proved Reserves and production rate forecasts of oil and condensate made by BP Exploration (Alaska) Inc. attributable to the BP Prudhoe Bay Royalty Trust as of December 31, 1994. Additionally, we reviewed calculations of the resulting Estimated Future Net Revenues and Present Value of Estimated Future Net Revenues attributable to the BP Prudhoe Bay Royalty Trust.

The estimates and calculations reviewed are summarized in the report prepared by BP Exploration (Alaska) Inc. and transmitted with a cover letter dated February 17, 1995, addressed to Ms. Marie Trimboli of The Bank of New York and signed by Mr. David K. Woodward. Reviews were also performed by Miller and Lents, Ltd. during this year or in previous years of (1) the procedures for estimating and documenting Proved Reserves, (2) the estimates of in-place reservoir volumes, (3) the estimates of recovery factors and production profiles for the various areas, pay zones, projects, and recovery processes that are included in the estimate of Proved Reserves, (4) the production strategy and procedures for implementing that strategy, (5) the sufficiency of the data available for making estimates of Proved Reserves and production profiles, and (6) pertinent provisions of

the Prudhoe Bay Unit Operating Agreement, the Issues Resolution Agreement, the Overriding Royalty Conveyance, the Trust Conveyance, the BP Prudhoe Bay Royalty Trust Agreement, and other related documents referenced in the Form F-3 Registration Statement filed with the Securities and Exchange Commission on August 7, 1989, by BP Exploration (Alaska) Inc.

Proved Reserves were estimated by BP Exploration (Alaska) Inc. in accordance with the definitions contained in Securities and Exchange Commission Regulation S-X, Rule 4-10(a). Estimated Future Net Revenues and Present Value of Estimated Future Net Revenues are not intended and should not be interpreted to represent fair market values for the estimated reserves.

The Prudhoe Bay (Permo-Triassic) Reservoir is defined in the Prudhoe Bay Unit Operating Agreement. The Prudhoe Bay Unit is an oil and gas unit situated on the North Slope of Alaska. The BP Prudhoe Bay Royalty Trust is entitled to a royalty payment on 16.4246 percent of the first 90,000 barrels of the actual average daily net production of oil and condensate for each calendar quarter from the BP Exploration (Alaska) Inc. working interest in the Prudhoe Bay Unit. The payment amount depends upon the Per Barrel Royalty which, in turn, depends upon the West Texas Intermediate Price, the Chargeable Costs, the Cost Adjustment Factor, and Production Taxes, all of which are defined in the Overriding Royalty Conveyance. "Barrel" as used herein means Stock Tank Barrel as defined in the Overriding Royalty Conveyance.

Our reviews do not constitute independent estimates of the reserves and annual production rate forecasts for the areas, pay zones, projects, and recovery processes examined. We relied upon the accuracy and completeness of information provided by BP Exploration (Alaska) Inc. with respect to pertinent ownership interests and various other historical, accounting, engineering and geological data.

As a result of our cumulative reviews, based on the foregoing, we conclude that:

1. A large body of basic data and detailed analyses are available and were used in making the estimates. In our judgment, the quantity and quality of currently available data on reservoir boundaries, original fluid contacts, and reservoir rock and fluid properties are sufficient to indicate that any future revisions to the estimates of total original in-place volumes should be minor. Furthermore, the data and analyses on recovery factors and future production rates are sufficient to support the Proved Reserves estimates.

2. The methods and procedures employed to accumulate and evaluate the necessary information and to estimate, document, and reconcile reserves, annual production rate forecasts, and future net revenues are effective and are in accordance with generally

accepted geological and engineering practice in the petroleum industry.

3. Based on our limited independent tests of the computations of reserves, production flowstreams, and future net revenues, such computations were performed in accordance with the methods and procedures described to us.

4. The estimated net remaining Proved Reserves attributable to the BP Prudhoe Bay Royalty Trust as of December 31, 1994, of 81.0 million barrels of oil and condensate are, in the aggregate, reasonable. All 81.0 million barrels are Proved Developed Reserves.

5. Utilizing the specified procedures outlined in Financial Accounting Standards Board Statement of Financial Accounting Standards No. 69, BP Exploration (Alaska) Inc. calculated that as of December 31, 1994, production of the Proved Reserves will result in Estimated Future Net Revenues of $257 million and Present Value of Estimated Future Net Revenues of $163 million to the BP Prudhoe Bay Royalty Trust. These estimates are reasonable.

6. BP Exploration (Alaska) Inc. estimated that, as of December 31, 1994, 668.0 million barrels of Proved Reserves have been added to Current Reserves. This estimate is reasonable. Current Reserves are defined in the Overriding Royalty Conveyance as net Proved Reserves of 2,035.6 million barrels as of December 31, 1987. Net additions to Proved Reserves after December 31, 1987 affect the Chargeable Costs that are used to calculate the Per Barrel Royalty paid to the BP Prudhoe Bay Royalty Trust.

7. The BP Exploration (Alaska) Inc. projection that its net production of oil and condensate from Proved Reserves will continue at an average rate exceeding 90,000 barrels per day until the year 2014 is reasonable. As long as the Per Barrel Royalty has a positive value, average daily production attributable to the BP Prudhoe Bay Royalty Trust will remain constant until the net production falls below 90,000 barrels per day; thereafter, production attributable to the BP Prudhoe Bay Royalty Trust will decline with the BP Exploration (Alaska) Inc. production. However, the Per Barrel Royalty will not have a positive value if the West Texas Intermediate Price is less than the sum of the per barrel Chargeable Costs and per barrel Production Taxes, appropriately adjusted in accordance with the Overriding Royalty Conveyance. Under such circumstances, average daily production attributable to the BP Prudhoe Bay Royalty Trust will have no value and therefore will not contribute to the reserves regardless of the BP Exploration (Alaska) Inc. net production level.

8. Based on the West Texas Intermediate Price of $17.75 per barrel on December 31, 1994, current Production Taxes, and the Chargeable Costs adjusted as prescribed by the Overriding Royalty Conveyance, the projection that royalty payments will continue through the year 2009 is reasonable. BP Exploration (Alaska) Inc. expects continued economic production at a declining rate through the year 2030; however, for the economic conditions and production forecast as of December 31, 1994, the Per Barrel Royalty will be zero following the year 2009. Therefore, no reserves are currently attributed to the BP Prudhoe Bay Royalty Trust after that date.

9. Even if expected reservoir performance does not change, the estimated reserves, economic life, and future revenues attributable to the BP Prudhoe Bay Royalty Trust may change significantly in the future. This may result from changes in the West Texas Intermediate Price or from changes in other prescribed variables utilized in calculations defined by the Overriding Royalty Conveyance.

Estimates of ultimate and remaining reserves and production scheduling depend upon assumptions regarding expansion or implementation of alternative projects or development programs and upon strategies for production optimization. BP Exploration (Alaska) Inc. has continual reservoir management, surveillance, and planning efforts dedicated to (1) gathering new information, (2) improving the accuracy of its reserves and production capacity estimates, (3) recognizing and exploiting new opportunities, (4) anticipating potential problems and taking corrective actions, and (5) identifying, selecting, and implementing optimum recovery program and cost reduction alternatives. Given this significant effort and ever-changing economic conditions, estimates of reserves and production profiles will change periodically.

The current estimate of Proved Reserves includes only those projects or development programs that are deemed reasonably certain to be implemented, given current economic and regulatory conditions. Future projects, development programs, or operating strategies different from those assumed in the current estimates may change future estimates and affect recoveries. However, because several complementary and alternative projects are being considered for recovery of the remaining oil in the reservoir, a decision not to implement a currently planned project may allow scope expansion or implementation of another project, thereby increasing the overall likelihood of recovering the reserves.

Future production rates will be controlled by facilities limitations and upsets, well downtime, and the effectiveness of programs to optimize production and costs. BP Exploration (Alaska) Inc. currently expects continued economic production from the reservoir at a declining rate through the year 2030. Additional drilling, workovers, facilities modifications, new recovery projects, and programs for production enhancement and optimization are expected to mitigate but not eliminate

the anticipated future decline in gross oil and condensate production capacity.

In making its future production rate forecasts, BP Exploration (Alaska) Inc. provided for normal downtime and planned facilities upsets. Although allowances for unplanned upsets are also considered in the estimates, the studies do not provide for any impediments to crude oil production as a consequence of major disruptions.

Under current economic conditions, gas from the Alaskan North Slope, except for minor volumes, cannot be marketed commercially. Oil and condensate recoveries are expected to be greater as a result of continued reinjection of produced gas than the recoveries would be if major volumes of produced gas were being sold. No major gas sale is assumed in the current estimates. If major gas sales are determined to be economically viable in the future, BP Exploration (Alaska) Inc. estimates that such sales would not actually commence until eight to ten years after such a determination. In the event that major gas sales are initiated, ultimate oil and condensate recoveries may be reduced from the current estimates unless recovery projects other than those included in the current estimates are implemented.

Large volumes of natural gas liquids are likely to be produced and marketed in the future whether or not major gas sales become viable. Natural gas liquids reserves are not included in the estimates cited herein. The BP Prudhoe Bay Royalty Trust is not entitled to royalty payments from production or sales of natural gas or natural gas liquids.

The evaluations presented in this report, with the exceptions of those parameters specified by others, reflect our informed judgments based on accepted standards of professional investigation but are subject to those generally recognized uncertainties associated with interpretation of geological, geophysical, and engineering information. Government policies and market conditions different from those reflected in this study or disruption of existing transportation routes or facilities may cause the total quantity of oil or condensate to be recovered, actual production rates, prices received, or operating and capital costs to vary from those reviewed in this report.

Miller and Lents, Ltd., is an independent oil and gas consulting firm. None of the principals of this firm have any direct financial interests in BP Exploration (Alaska) Inc. or its parent or any related companies or in the BP Prudhoe Bay Royalty Trust. Our fee is not contingent upon the results of our work or report, and we have not performed other services for

BP Exploration (Alaska) Inc. or the BP Prudhoe Bay Royalty Trust that would affect our objectivity.

Very truly yours,

MILLER AND LENTS, LTD.

By /s/ William P. Koza

William P. Koza
Vice President

WPK/hsd

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 the Company and the Trust were based on Company prepared reserve estimates.

The reserves attributable to the Trust are only a part of the overall above stated reserves. There is no precise method of allocating estimates of physical quantities of reserve volumes between the Company 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 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 WTI Prices on December 31, 1994 ($17.75 per barrel), December 31, 1993 ($14.15 per barrel), December 31, 1992 ($19.50 per barrel), December 31, 1991 ($19.10 per barrel), and December 31, 1990 ($28.45 per barrel). Because the reserve volumes attributable to the Trust are estimated using an allocation of reserve volumes based on estimated future production, the current WTI Price, no future movement in the CPI, and no future additions by the Company of Proved Reserves to Current Reserves, a change in the timing of estimated production, a change in the WTI Price, future movement in the CPI, or future additions by the Company of Proved Reserves to Current Reserves 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. See "Financial Statements" and Note 5 thereto.

Estimated net proved reserves allocable to the Trust as of December 31, 1994, December 31, 1993 and December 31, 1992 were 80,991,000 barrels, 43,193,000 barrels and 94,306,000 barrels, respectively. See "Financial Statements" and Note 5 thereto. The decrease from December 31, 1992 to December 31, 1993 reflects the excess of production over additions and changes in timing of production and the decrease in the WTI Price from $19.50 per barrel on December 31, 1992 to $14.15 per barrel on December 31, 1993. The increase from December 31, 1993 to December 31, 1994 reflects the increase in the WTI Price from $14.15 per barrel on December 31, 1993 to $17.75 per barrel on December 31, 1994. Proved developed reserves allocable to the Trust as of December 31, 1994, December 31, 1993 and December 31, 1992 were 80,991,000 barrels, 43,193,000 barrels and 79,420,000 barrels, respectively.

The Company 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 PBU working interest owners. However, several such investments which would augment Prudhoe Bay projects are already in process. These include additional drilling, waterflood expansions and miscible injection continuation/ expansion projects. Other possible investments could include expanded gas cycling, miscible/waterflood infill drilling, miscible injection supply increases to peripheral areas, heavy oil tar recovery and development of the smaller reservoirs. While there is no assurance that the PBU working

interest owners will make any such investments, they do regularly assess the technical and economic attractiveness of implementing further projects to increase PBU proved reserves.

As noted above, the Company's reserve estimates and production assumptions and projections are predicated upon a reasonable estimate of hydrocarbon allocation between oil and condensate. The Company's share of Prudhoe Bay production is the sum of 50.68% of the gross oil production and 13.84% of the gross condensate production from the Field. 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 Field is a theoretical calculation performed in accordance with procedures specified in the Prudhoe Bay Unit Operating Agreement. Due to the differences in percentages between oil and condensate, the Company's overall share of oil and condensate production will vary over time according to the proportions of hydrocarbon liquid being allocated as condensate or as oil under the Prudhoe Bay Unit Operating Agreement allocation procedures. Under the terms of the IRA effective October 4, 1990 the present allocation procedures will be adjusted in 1995 to generally allocate condensate in a manner which approximates the anticipated decline in the production of oil until the agreed condensate reserve of 1.175 billion STB has been allocated to the Working Interest Owners. The Company believes this is a reasonable estimate of hydrocarbon allocation between oil and condensate.

The occurrence of major gas sales could accelerate the time at which the Company's net production would fall below 90,000 barrels per day, due to the consequent decline in reservoir pressure.

In the event of changes in the Company'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.

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 Field reserves.

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

TRANSPORTATION OF PRUDHOE BAY OIL

Production from the Field is carried to Pump Station 1, which is the starting point for TAPS, through two 34-inch diameter transit lines, one

from each half of the Field. At Pump Station 1, Alyeska Pipeline Service Company, the pipeline operator, meters the oil and pumps it south to Valdez where it is either loaded onto marine tankers or stored temporarily. It takes the oil about six days to make the trip in the 48-inch diameter pipeline.

During 1989, analysis of data gathered by newly developed corrosion monitoring pigs revealed areas of corrosion previously undetected on TAPS. All of the corrosion found during 1989 was clustered largely in 13.5 miles, or less than 2%, of the pipeline length.

In 1989, analysis of data gathered by sophisticated corrosion monitoring pigs identified previously undetected corrosion on TAPS. An innovative approach enabled an 8.5 mile section of pipe to be replaced in 1991 without disrupting shipments from the terminal to Valdez. In 1992, instead of being replaced, a two mile section near Chandalar received specific repairs. This and other developments have cut the cost of repairs on the main line. Pump station piping corrosion costs have also been reduced significantly. The State of Alaska filed protests to the 1990, 1991, 1992, 1993, 1994 and 1995 TAPS tariffs, seeking to exclude corrosion costs from the tariffs charged to ship oil through TAPS. The State of Alaska and the other parties have agreed to continue attempts to resolve the dispute among themselves. Additional protests were filed by the State of Alaska in 1994 challenging the inclusion of certain public affairs and other expenses in such tariffs. A further protest has been filed by the State of Alaska relating to the 1995 tariff challenging the inclusion of certain expenses incurred in remediation of matters connected with National Electrical Codes.

HISTORICAL PRODUCTION OF OIL AND CONDENSATE

The following table sets forth information concerning the production of oil and condensate for the periods indicated. The amounts listed are the Company's share of production, net of royalties to the State of Alaska.

HISTORICAL PRODUCTION

Year Ended December 31,	Oil and Condensate Produced (bpd)
1987	687,000(a)
1988	652,500
1989	587,200
1990	540,000
1991	530,000
1992	481,800
1993	417,700
1994	369,900

(a) Reflects an overlifting of 13,500 barrels per day through August 31, 1987 resulting from the redetermination of the MPC group ownership of the PBU. See "Oil Rim Redetermination" above.

INDUSTRY CONDITIONS

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, the Company's oil and gas activities are subject to laws and regulations relating to environmental quality and pollution control. The Company 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. Although the existence of legislation and regulation has had no material adverse effect on the Company's current method of operations, existing and future legislation and regulations could result in the Company experiencing delays and uncertainties in commencing projects. The ultimate impact of such legislation and regulations cannot generally be predicted.

Oil prices are subject to international supply and demand. Political developments (especially in the Middle East) and the outcome of meetings of OPEC can particularly affect world oil supply and oil prices.

CERTAIN TAX CONSIDERATIONS

The following is a summary of the principal tax consequences to the Trust Unit holders resulting from the ownership and disposition of Trust Units. The laws or regulations affecting these matters are subject to change by future legislation or regulations or new interpretations by the IRS, state taxing authorities or the courts, which could adversely affect Trust Unit holders. In addition, there may be differences of opinion as to the applicability or interpretation of present tax laws or regulations. BP and the Trust have not requested from the IRS any rulings on the tax treatment described below, and no assurance can be given that such tax treatment will be available.

Taxpayers are urged to consult their tax advisors on the application of the following discussion to their specific circumstances.

EMPLOYEES

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

FEDERAL INCOME TAX

CLASSIFICATION OF THE TRUST

The Trust files its federal tax return as a "grantor trust" rather than as "an association taxable as a corporation." 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. The following discussion is based on the legal conclusion that the Trust will be classified as a grantor trust under current law.

TAXATION OF THE TRUST

A grantor trust is not subject to tax, and its beneficiaries (the Trust Unit holders in the case of the Trust) are considered for tax purposes to own its income and corpus. A grantor trust files an information return reporting all items of income or deduction. The Trust, therefore, will pay no federal income tax, but will file an information return.

TAXATION OF TRUST UNIT HOLDERS

The income of the Trust will be deemed to have been received or accrued by the Trust Unit holders at the time such income is received or accrued by the Trust and not when distributed by the Trust. Income will be recognized by a Trust Unit holder consistent with its method of accounting and without regard to the accounting period or method employed by the Trust.

The Trust will make quarterly distributions to Trust Unit holders of record on each Quarterly Record Date. See "Description of the Trust Units and the Trust Agreement--Distributions of Income." The terms of the Trust Agreement as described above, seek to assure to the extent practicable that taxable income attributable to such distributions will be reported by the Trust Unit holder who receives such distributions, assuming that such holder is the owner of record on the Quarterly Record Date. In certain circumstances, however, a Trust Unit holder may be required to report taxable income attributable to its Trust Units, but the Trust Unit holder will not receive the distribution attributable to such income. For example, if the Trustee establishes a reserve or borrows money to satisfy debts and liabilities of the Trust income used to establish such reserve or to repay such loan must be reported by the Trust Unit holder, even though such income is not distributed to the Trust Unit holder.

The Trust intends to allocate income and deductions to Trust Unit holders based on record ownership at Quarterly Record Dates. It is unknown whether the IRS will accept such allocation or will require income and deductions of the Trust to be determined and allocated daily or require some method of daily proration, which could result in an increase in the administrative expenses of the Trust.

It is anticipated that each Trust Unit holder will be entitled to a deduction for cost depletion and certain other deductions for state and local taxes imposed upon the Trust or a Trust Unit holder and administrative expenses of the Trust. A Trust Unit holder's deduction for cost depletion in any year will be calculated by multiplying the holder's adjusted tax basis in the Trust Units (generally its 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. Trust Unit holders acquiring units on or after October 12, 1990 are possibly permitted to utilize percentage depletion with respect to such Units. Percentage depletion is based on the Trust Unit holders 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 Trust Unit holder will reduce its adjusted basis in its Trust Units for purposes of computing subsequent depletion or gain or loss on any subsequent disposition of Trust Units.

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

TAXATION OF NONRESIDENT ALIEN INDIVIDUALS, PARTNERSHIPS AND FOREIGN CORPORATIONS

Generally, nonresident alien individuals, partnerships and foreign corporations (i.e., Foreign persons) are subject to a tax of 30 percent on gross income from sources within the U.S. that are not from a U.S. trade or business. Income from the Trust is considered income which is not effectively connected with a U.S. trade or business. As a result, Foreign persons would be subject to a 30 percent tax on their gross income from the Trust, without deductions. Usually such tax is to be withheld at the source of payment by the withholding agent. However, if there is a treaty in effect between the U.S. and the country of residence of the foreign person, such treaty may reduce the rate of withholding.

A holder of Trust Units who is a Foreign person may make an election pursuant to Internal Revenue Code Section 871 (d) or 882(d), or pursuant to any similar provisions of applicable treaties, to treat the income (which constitutes income from real property) from the Trust as income which is effectively connected with a U.S. trade or business. If this election is made such a holder of Trust Units will not be subject of withholding but will, however, be taxed on such income in the same manner as a U.S. person (i.e. U.S. individual, partnership or corporation). As a result, such holder of Trust Units will be taxed on his net income as opposed to his gross income from the Trust. Also, under such an election, any gain or loss upon the disposition of a Trust Unit will be deemed to be connected with a U.S. trade or business and taxed in the manner described above. If a Foreign person owns a greater than 5 percent interest in the Trust, that interest is a U.S. real property interest as provided under Internal Revenue Code Section 897. Gain on disposition of that interest will be taxed as if the holder of Trust Units were a U.S. person. In addition, Foreign persons subject to Internal Revenue Code Section 897 who are nonresident alien individuals will be subject to a minimum tax of 26 percent or 28 percent (depending on filing status and taxable income) on the lesser of:

1. the individual's alternative minimum taxable income for the taxable year, or

2. the net gain from the disposal of the Trust Unit.

Gain or loss on the disposition is determined by subtracting the adjusted basis of the Trust Units from the proceeds received. If the Foreign person is a corporation which made an election under Internal Revenue Code Section 882(d), the corporation would also be subject to a 30 percent 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 TRUST UNITS

Generally, a Trust Unit holder will realize gain or loss on the sale or exchange of his Trust Units measured by the difference between the amount realized on the sale or exchange and his adjusted basis for such Trust Units. Gain on the sale of Trust Units by a holder that is not a dealer with respect to such Trust Units will be treated as ordinary income to the extent of any depletion deductions taken by such holder and the balance, if any, of the gain will be treated as capital gain.

BACKUP WITHHOLDING

A payor must withhold 31 percent 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. A Unit holder will avoid backup withholding by furnishing his correct TIN to the Trustee in the form required by law.

REPORTS

The Trustee will furnish the Trust Unit holders of record quarterly and annual reports described above under "Description of the Trust Units and the Trust Agreement-Reports to Holders of Trust Units" in order to permit computation of tax liability by the Trust Unit holders.

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 does not impose an income tax on individuals or estates and trusts. Corporate Unit holders should be advised that all Trust income is Alaska source income and should be reported accordingly.

ITEM 2. PROPERTIES

Reference is made to "Item I.- Business" for the information required by this item.

ITEM 3. LEGAL PROCEEDINGS

Not applicable.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF UNIT HOLDERS

Not applicable.

PART II

ITEM 5. MARKET FOR TRUST UNITS

The Trust Units are listed on the New York Stock Exchange ("NYSE"). The following table represents the high and low per unit sales prices for the Trust Units as reported on the consolidated tape for 1993 and 1994 and the distributions paid by the Trust for the periods presented.

	High		Low		Distributions Per Trust Unit	
	1993	1994	1993	1994	1993	1994
First Quarter	$31.750	$27.000	$29.500	$23.000	0.590	0.228
Second Quarter	$31.625	$24.000	$27.750	$19.125	0.595	0.396
Third Quarter	$29.625	$24.000	$26.125	$21.250	0.499	0.436
Fourth Quarter	$29.625	$22.375	$23.875	$15.750	0.424	0.390

As of March 21, 1995, there were 1,708 registered holders of Trust Units.

Future payments of cash distributions are dependent on such factors as the prevailing WTI Price, 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 production from the PBU.

ITEM 6. SELECTED FINANCIAL DATA

Reference is made to "Item 1. - Report of Miller and Lents, Ltd., Independent Petroleum Consultants" of this Annual Report on Form 10-K.

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

BP PRUDHOE BAY ROYALTY TRUST
Statements of Cash Earnings and Distributions
For each of the years in the five-year period ended
December 31, 1994, 1993, 1992, 1991 and 1990 and for the period
of February 28, 1989 (date of formation)
to December 31, 1989
(In thousands, except unit data)

	1994	1993	1992	1991	1990	1989
Royalty revenues	$ 32,401	51,727	65,250	87,010	76,788	40,776
Trust administrative expenses	658	554	413	412	457	170

Cash earnings	31,743	51,173	64,837	86,598	76,331	40,606
Cash distributions	31,743	51,173	64,837	86,598	76,331	40,606
Cash distributions per unit	$ 1.483	2.391	3.030	4.046	3.567	1.897
Units outstanding	$21,400,000	21,400,000	21,400,000	21,400,000	21,400,000	21,400,000

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

FINANCIAL CONDITION

The Trust is a passive entity with the Trustee having only such powers as are necessary for the collection and distribution of revenues from the Royalty Interest, the payment of Trust liabilities and expenses and the protection of the Royalty Interest. All royalty payments received by the Trustee are distributed, net of Trust expenses, to Trust Unit holders. Accordingly, a discussion of liquidity or capital resources is not applicable.

RESULTS OF OPERATIONS

Payments to the Trust with respect to the Royalty Interest are generally payable on the fifteenth day after the end of the calendar quarter (or the next succeeding business day if such fifteenth day is not a business day) in an amount equal to the per barrel WTI Price for each day during the calendar quarter less the sum of (i) the product of the per barrel Chargeable Costs and the Cost Adjustment Factor (such product hereinafter referred to as "Adjusted Chargeable Costs") and (ii) the per barrel Production Taxes, multiplied by the Royalty Production.

ACTUAL RESULTS

During 1994 the Trust received payments with respect to the Royalty Interest in the aggregate amount of $32,401,000 and made distributions to Unit holders in the aggregate amount of $31,743,000. The payment with respect to the Royalty Interest for the calendar quarter ended December 31, 1994, which was paid to the Trust on January 17, 1995, was $8,478,000. The following table sets forth with respect to each calendar quarter the average WTI price, the per barrel Chargeable Costs, the Cost Adjustment Factor, the per barrel Adjusted Chargeable Costs, the per barrel Production Taxes, and the Per Barrel Royalty.

CALENDAR YEARS 1994, 1993, AND 1992

	1/1-3/31			4/1-6/30			7/1-9/3			10/1-12/31		
	1994	1993	1992	1994	1993	1992	1994	1993	1992	1994	1993	1992
Average WTI Price	$14.80	$19.85	$18.94	$17.79	$19.76	$21.20	$18.49	$17.77	$21.67	$17.67	$16.43	$20.50
Chargeable Costs	8.00	6.75	6.00	8.00	6.75	6.00	8.00	6.75	6.00	8.00	6.75	6.00
Cost Adjustment Factor	1.180	1.171	1.134	1.180	1.180	1.143	1.192	1.180	1.153	1.192	1.180	1.162
Adjusted												

Chargeable Costs	9.44	7.90	6.80	9.44	7.96	6.86	9.53	7.96	6.92	9.53	7.96	6.97
Production Taxes	1.48	2.24	2.13	1.93	2.22	2.46	2.02	1.92	2.53	1.90	1.72	2.34
Per Barrel Royalty	3.88	9.71	10.00	6.42	9.57	11.88	6.93	7.88	12.23	6.23	6.74	11.18

(All Figures after rounding)

As discussed above in Part I "Industry Conditions" the production of oil and gas in Alaska is affected by many state and federal regulations. Existing and future legislation and regulations could result in the Company's experiencing delays and uncertainties, although the ultimate impact cannot generally be predicted. Per barrel royalty payments will also remain subject to oil prices, to the WTI Price, to Chargeable Costs, which increase in accordance with the schedule contained above under "Description of the Royalty Interest-Chargeable Costs", to the Cost Adjustment Factor, which is based on CPI, and to Production Taxes, which increased in accordance with the discussion above under "Production Taxes".

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA.

BP PRUDHOE BAY ROYALTY TRUST
INDEX TO FINANCIAL STATEMENTS

INDEPENDENT AUDITORS' REPORT

Trustee and Holders of Trust Units of
BP Prudhoe Bay Royalty Trust:

We have audited the accompanying statements of assets, liabilities and Trust Corpus of BP Prudhoe Bay Royalty Trust as of December 31, 1994 and 1993, 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, 1994. These financial statements are the responsibility of the Trustee. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with generally accepted auditing standards. 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 have been prepared on a modified basis of cash receipts and disbursements, which is a comprehensive basis of accounting other than generally accepted accounting principles.

In our opinion, the financial statements referred to above present fairly, in all material respects, the assets, liabilities and Trust Corpus of BP Prudhoe Bay Royalty Trust as of December 31, 1994 and 1993, and its cash earnings and distributions and its changes in Trust Corpus for each of the years in the three-year period ended December 31, 1994, on the basis of accounting described in note 2.

KPMG Peat Marwick LLP

New York, New York
March 22, 1995

BP PRUDHOE BAY ROYALTY TRUST

Statements of Assets, Liabilities and Trust Corpus

December 31, 1994 and 1993
(In thousands, except unit data)

ASSETS	1994	1993
Royalty Interest (notes 1 and 2)	$ 535,000	535,000
Less: accumulated amortization	(194,689)	(127,859)
Total assets	$ 340,311	407,141
LIABILITIES AND TRUST CORPUS		
Accrued expenses	$ 118	84
Trust Corpus (40,000,000 units of beneficial interest authorized, 21,400,000 units issued and outstanding)	340,193	407,057
Contingencies (note 3)		
Total liabilities and Trust Corpus	$ 340,311	407,141

See accompanying notes to financial statements.

BP PRUDHOE BAY ROYALTY TRUST

Statements of Cash Earnings and Distributions

For the Years Ended December 31, 1994, 1993 and 1992
(In thousands, except unit data)

	1994	1993	1992
Royalty revenues	$ 32,401	51,727	65,250
Trust administrative expenses	658	554	413
Cash earnings	$ 31,743	51,173	64,837
Cash distributions	$ 31,743	51,173	64,837
Cash distributions per unit	$ 1.483	2.391	3.030
Units outstanding	21,400,000	21,400,000	21,400,000

See accompanying notes to financial statements.

BP PRUDHOE BAY ROYALTY TRUST

Statements of Changes in Trust Corpus

For the Years Ended December 31, 1994, 1993 and 1992
(In thousands)

	1994	1993	1992
Trust Corpus at beginning of year	$ 407,057	437,666	467,158
Cash earnings	31,743	51,173	64,837
Decrease (increase) in accrued Trust expenses	(34)	-	1
Cash distributions	(31,743)	(51,173)	(64,837)
Amortization of Royalty Interest	(66,830)	(30,609)	(29,493)
Trust Corpus at end of year	$ 340,193	407,057	437,666

See accompanying notes to financial statements.

BP PRUDHOE BAY ROYALTY TRUST

Notes to Financial Statements

December 31, 1994, 1993 and 1992

(1) FORMATION OF THE TRUST AND ORGANIZATION

BP Prudhoe Bay Royalty Trust (the "Trust") was formed pursuant to a Trust Agreement dated February 28, 1989 among The Standard Oil Company ("Standard Oil"), BP Exploration (Alaska) Inc. (the "Company"), The Bank of New York and a co-trustee (collectively, the "Trustee"). Standard Oil and the Company are indirect wholly owned subsidiaries of the British Petroleum Company 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") on 16.4246% of 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 the Company's working interest in the Prudhoe Bay Field (the "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 or fall, on average, below 90,000 barrels per day in any quarter. BP has guaranteed the performance by the Company of its payment obligations with respect to the Royalty Interest.

The co-trustees of the Trust are The Bank of New York, a New York corporation authorized to do a banking business, and The Bank of New York (Delaware), a Delaware banking corporation. The Bank of New York (Delaware) serves as co-trustee in order to satisfy certain requirements of the Delaware Trust Act. The Bank of New York 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 in certain situations for inflation) and Production Taxes (based on statutory rates then in existence). During the period from February 28, 1989 (date of formation) to September 30, 1991, the Royalty Interest provided for a minimum royalty in certain situations. For years subsequent to 1995, Chargeable Costs will be reduced up to a maximum amount of $1.20 per barrel in each year if additions to the Field's proved reserved from January 1, 1988 do not meet certain specific levels.

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 upon the first to occur of the following events:

(a) On or prior to December 31, 2010: upon a vote of Trust Unit holders of not less than 70% of the outstanding Trust Units.

(b) After December 31, 2010: (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 commencing after 2010 are less than $1,000,000 per year (unless the net revenues during such period are materially and adversely affected by certain events).

(Continued)

BP PRUDHOE BAY ROYALTY TRUST

Notes to Financial Statements

(2) BASIS OF ACCOUNTING

The financial statements of the Trust are prepared on a modified cash basis and reflect the Trust's assets, liabilities and Trust Corpus and the 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 when incurred.

(c) Amortization of the Royalty Interest is calculated based on the units of production attributable to the Trust over the production of estimated proved reserves attributable to the Trust at the beginning of the fiscal year (approximately 43,193,000, 94,306,000 and 98,141,000 barrels were used to calculate the amortization of the Royalty Interest for the years ended December 31, 1994, 1993 and 1992, respectively), is charged directly to the Trust Corpus, and does not affect cash earnings. The rate for amortization per net equivalent barrel of oil was $12.39, $5.67 and $5.45 for the years ended December 31, 1994, 1993 and 1992, respectively. The remaining unamortized balance of the net overriding Royalty Interest at December 31, 1994 is not necessarily indicative of the fair market value of the interest held by the Trust.

While these statements differ from financial statements prepared in accordance with generally accepted accounting principles, the cash basis of reporting revenues and distributions is considered to be the most meaningful because quarterly distributions to the Unit holders are based on net cash receipts

The conveyance of the Royalty Interest by Standard Oil to the Trust was accounted for as a purchase transaction. On February 28, 1989, Standard Oil sold 13,360,000 Trust Units to a group of institutional investors for $334 million in a private placement. For financial reporting purposes, the Trust's management valued the remaining Trust Units owned by Standard Oil (8,040,000 units) at a per unit value equivalent to the amount paid by the investors in the private placement.

(3) 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 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 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.

(Continued)

BP PRUDHOE BAY ROYALTY TRUST

Notes to Financial Statements

(4) SUMMARY OF QUARTERLY RESULTS (UNAUDITED)

A summary of selected quarterly financial information for the years ended December 31, 1994 and 1993 is as follows (in thousands, except unit data):

	1ST QUARTER	2ND QUARTER	3RD QUARTER	4TH QUARTER
1994				
Royalty revenues	$ 9,172	5,164	8,640	9,425
Trust administrative expenses	100	284	171	103
Cash earnings	9,072	4,880	8,469	9,322
Cash distributions	9,072	4,880	8,469	9,322
Cash distributions per unit	0.424	0.228	0.396	0.436
1993				
Royalty revenues	$15,209	12,918	12,878	10,722
Trust administrative expenses	84	286	142	42
Cash earnings	15,125	12,632	12,736	10,680
Cash distributions	15,125	12,632	12,736	10,680
Cash distributions per unit	0.707	0.590	0.595	0.499

(5) SUPPLEMENTAL RESERVE INFORMATION AND STANDARDIZED MEASURE OF DISCOUNTED FUTURE NET CASH FLOW RELATING TO PROVED RESERVES (UNAUDITED)

Pursuant to Statement of Financial Accounting Standards No. 69 - "Disclosures About Oil and Gas Producing Activities" ("FASB 69"), 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.

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 the Company and the Trust were based on Company-prepared reserve estimates. The Company's reserve estimates are believed to be reasonable and consistent with presently known physical data concerning the size and character of the Field.

There is no precise method of allocating estimates of physical quantities of reserve volumes between the Company 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 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 WTI Price on December 31, 1994 ($17.75 per barrel), December 31, 1993 ($14.15 per barrel) and December 31, 1992 ($19.50 per barrel). Because the reserve volumes attributable to the Trust are estimated using an allocation of reserve volumes based on 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.

(Continued)

(5), Continued

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. The Royalty Interest includes a provision under which, in years subsequent to 1995, if additions to the Field's proved reserves from January 1, 1988 do not meet certain specified levels, Chargeable Costs will be reduced up to a maximum amount of $1.20 per barrel in each year. Under the provisions of FASB 69, no consideration can be given to reserves not considered proved at the present time. Accordingly, in estimating the reserve volumes attributable to the Trust, Chargeable Costs were reduced by the maximum amount in years subsequent to 1995, after considering the amount of reserves that have been added to the Field's proved reserves from January 1, 1988.

Net proved reserves of oil and condensate attributable to the Trust as of December 31, 1994, 1993 and 1992 based on the Company's latest reserve estimate at such time, the WTI Prices on December 31, 1994, 1993 and 1992 and a reduction in Chargeable Costs in years subsequent to 1995, were estimated to be 81, 43 and 94 million barrels, respectively (of which 81, 43 and 79 million barrels, respectively, are proved developed).

The standardized measure of discounted future net cash flow relating to proved reserves disclosure required by FASB 69 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 increases 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, 1994, 1993 and 1992 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 69), based on the WTI Prices on those dates of $17.75, $14.15 and $19.50, respectively, were as follows (in thousands):

	DECEMBER 31, 1994	DECEMBER 31, 1993	DECEMBER 31, 1992
Future net cash flows	$ 257,080	83,735	498,966
10% annual discount for estimated timing of cash flows	(93,935)	(18,563)	(214,670)
Standardized measure of discounted future net cash flow relating to proved reserves (a)	$ 163,145	65,172	284,296

(a) The standardized measure of discounted future net cash flow relating to proved reserves, estimated without reducing Chargeable Costs in years subsequent to 1995, would be $154,200, $65,174 and $228,566 at December 31, 1994, 1993 and 1992, respectively.

(Continued)

BP PRUDHOE BAY ROYALTY TRUST

Notes to Financial Statements

(5), Continued

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

	1994	1993	1992
Revisions of prior estimates:			
Reserve volumes	$ 28,853	16,747	1,272
WTI price	115,530	(245,140)	26,168
Chargeable costs - inflation	(3,300)	(8,537)	(20,433)
Production taxes	(17,093)	37,347	(2,760)
Other	(827)	(2,280)	(2,564)
	123,163	(201,863)	1,683
Royalty income received (b)	(31,707)	(45,691)	(61,273)
Accretion of discount	6,517	28,430	31,262
Net increase (decrease) during the year	$ 97,973	(219,124)	(28,328)

(b) Royalty income received for 1994, 1993 and 1992 includes the royalty applicable to the period October 1, 1994 through December 31, 1994 ($8,478), October 1, 1993 through December 31, 1993 ($9,172) and October 1, 1992 through December 31, 1992 ($15,209), which was received by the Trust in January 1995, 1994 and 1993, respectively.

The changes in quantities of proved oil and condensate were as follows (thousands of barrels):

Estimated net proved reserves of oil and condensate at December 31, 1992	94,306
Production	(5,395)
Change in timing of estimated production	(45,718)

Estimated net proved reserves of oil and condensate at December 31, 1993	43,193
Production	(5,395)
Change in timing of estimated production	43,193

Estimated net proved reserves of oil and condensate at December 31, 1994	80,991
	======
Proved developed reserves:	
December 31, 1992	79,424
	======
December 31, 1993	43,193
	======
December 31, 1994	80,991
	======

ITEM 9. CHANGES IN ACCOUNTANTS

The Trust dismissed Ernst & Whinney as its independent accountants on June 15, 1989 and, as of the same date, engaged KPMG Peat Marwick (now KPMG Peat Marwick LLP) as independent accountants.

A Form F-3 Registration Statement (Registration No. 33-27923) filed by BP, the Company, and Standard Oil contained a single financial statement of the Trust audited by Ernst & Whinney, namely, a Statement of Assets and Trust corpus as of February 28,1989. The report of Ernst & Whinney on the Statement of Assets and Trust corpus contained in Registration Statement No. 33-27923 did not contain an adverse opinion or disclaimer of opinion and was not qualified or modified as to uncertainty, audit scope or accounting principles. During the period from February 28, 1989 through June 15, 1989 there were no disagreements with Ernst & Whinney on any matter of accounting principles or practices, financial statement disclosure, or auditing scope or procedure, which disagreements if not resolved to the satisfaction of Ernst & Whinney would have caused them to make reference thereto in their report on the Statement of Assets and Trust corpus as of February 28, 1989. During the period from February 28, 1989 through June 15, 1989, there were no reportable events (as defined in Regulation S-K Item 304(a)(1)(v)) with Ernst & Whinney. Ernst & Whinney has furnished the Trust with a copy of a letter addressed to the Securities and Exchange Commission stating that it agreed with the above statements.

PART III

ITEM 10. DIRECTORS AND EXECUTIVE OFFICERS

The Trust has no directors or executive officers. The Trustee has only such rights and powers as are necessary to achieve the purposes of the Trust.

ITEM 11. EXECUTIVE COMPENSATION

Not applicable.

ITEM 12. UNIT OWNERSHIP

(a) Unit Ownership of Certain Beneficial Owners.

As of March 21, 1995 the Trustee does not know of any person beneficially owning 5% or more of the Trust Units except based on filings with the Securities and Exchange Commission dated as of December 31, 1994, which filings set forth the following:

Name	No. of Units	Percentage
J.P. Morgan & Co., Inc. 23 Wall Street New York, N.Y. 10007	2,065,100(1)	9.6
Prudential Insurance Company of America 3 Gateway Center Newark, N.J. 07102	3,001,600(1)	14

(1) Amount known to be Units with respect to which beneficial owner has the right to acquire beneficial ownership: None.

(b) Unit Ownerships of Management

Neither the Company, Standard Oil, nor BP owns any Units. Neither The Bank of New York, as Trustee, or in its individual capacity, nor The Bank of New York (Delaware), as co-trustee, or in its individual capacity, owns any Units.

(c) Change 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.

ITEM 13. CERTAIN RELATIONSHIPS AND RELATED TRANSACTIONS

Not Applicable.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) FINANCIAL STATEMENTS

The following financial statements of the Trust are included in Part II, Item 8:

Page

(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. Form of Trust Agreement (incorporated by reference to Exhibit 6 to the Form 8-A Registration Statement of BP Prudhoe Bay Royalty Trust, Commission File No. 1-10243).

10.1 Form of Trust Conveyance dated February 28, 1989 (incorporated by reference to Exhibit 6 to the Form 8-A Registration Statement of BP Prudhoe Bay Royalty Trust, Commission File No. 1-10243).

10.2 Form of Overriding Royalty Conveyance dated February 27, 1989 (incorporated by reference to Exhibit 6 to the Form 8-A Registration Statement of BP Prudhoe Bay Royalty Trust, Commission File No. 1-10243).

16. Letter of Ernst & Whinney dated June 15, 1989 re change in certifying accountant (incorporated by reference to Exhibit 16 to Form 8-K Current Report of BP Prudhoe Bay Royalty Trust, Commission File No. 1-10243).

23. Consent of Expert - (See Exhibit 23.1 attached hereto).

27. Financial Data Schedule - (See Exhibit 27.1 attached hereto).

ALL OTHER EXHIBITS HAVE BEEN OMITTED BECAUSE THEY ARE EITHER NOT APPLICABLE OR NOT REQUIRED.

(d) REPORTS ON FORM 8-K

No reports on Form 8-K were filed with the Securities and Exchange Commission by the Trust during the quarter ending in December 31, 1994.

SIGNATURE

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

THE BANK OF NEW YORK, as Trustee

By: /s/ Walter Gitlin

Walter Gitlin
Vice President

March 29, 1995

The Registrant, BP Prudhoe Bay Royalty Trust, has no principal executive officer, principal financial officer, board of directors or persons performing similar functions. Accordingly, no additional signatures are available and none have been provided.

EXHIBIT INDEX

4. Form of Trust Agreement (incorporated by reference to Exhibit 6 to the Form 8-A Registration Statement of BP Prudhoe Bay Royalty Trust, Commission File No. 1-10243).

10.1 Form of Trust Conveyance dated February 28, 1989 (incorporated by reference to Exhibit 6 to the Form 8-A Registration Statement of BP Prudhoe Bay Royalty Trust, Commission File No. 1-10243).

10.2 Form of Overriding Royalty Conveyance dated February 27, 1989 (incorporated by reference to Exhibit 6 to the Form 8-A Registration Statement of BP Prudhoe Bay Royalty Trust, Commission File No. 1-10243).

16. Letter of Ernst & Whinney dated June 15, 1989 re change in certifying accountant (incorporated by reference to Exhibit 16 to Form 8-K Current Report of BP Prudhoe Bay Royalty Trust, Commission File No. 1-10243).

23. Consent of Expert - (See Exhibit 23.1 attached hereto).

27. Financial Data Schedule - (See Exhibit 27.1 attached hereto).

EXHIBIT 23.1

CONSENT OF MILLER AND LENTS, LTD.

MILLER AND LENTS, LTD.
OIL AND GAS CONSULTANTS

TWENTY-SEVENTH FLOOR
1100 LOUISIANA
HOUSTON, TEXAS 77002-5216

Telephone 713 651-9455
Telefax 713 654-9914

March 25, 1995

BP Prudhoe Bay Royalty Trust
c/o The Bank of New York, Trustee
101 Barclay Street, 21st Floor West
New York, New York 10286

Re: Securities and Exchange Commission
Form 10K of the
BP Prudhoe Bay Royalty Trust

Gentlemen:

The firm of Miller and Lents, Ltd. consents to the use of its name and to the use of its report dated February 28, 1995 regarding the Estimates of Proved Reserves, Future Annual Production Rates and Future Net Revenues for the BP Prudhoe Bay Royalty Trust As of December 31, 1994, which report is to be included in Form 10-K to be filed by the BP Prudhoe Bay Royalty Trust with the Securities and Exchange Commission.

Miller and Lents, Ltd. has no interests in the BP Prudhoe Bay Royalty Trust, or in any of its affiliated companies or subsidiaries and is not to receive any such interest as payment for such report and has no director, officer, or employee employed or otherwise connected with the BP Prudhoe Bay Royalty Trust. We are not employed by the BP Prudhoe Bay Royalty Trust on a contingent basis.

Yours very truly,

MILLER AND LENTS, LTD.

By: /s/ Walter Crow

Walter Crow
Chairman

<ARTICLE> 5
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THIS SCHEDULE CONTAINS SUMMARY FINANCIAL INFORMATION EXTRACTED FROM THE STATEMENTS OF ASSETS, LIABILITES AND TRUST CORPUS AND THE STATEMENTS OF CHANGES IN TRUST CORPUS AND IS QUALIFIED IN ITS ENTIRETY BY REFERENCE TO SUCH FINANCIAL STATEMENTS.
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