PARAMOUNT ENERGY TRUST

# ANNUAL INFORMATION FORM

**FOR THE YEAR ENDED DECEMBER 31, 2009**

**DATED: March 9, 2010**

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## ABBREVIATIONS

| Natural Gas | | Oil and Liquids | |
|---|---|---|---|
| Mcf | thousand cubic feet | Bbl | barrels |
| MMcf | million cubic feet | Mbbl | thousand barrels |
| Bcf | billion cubic feet | Bpd | barrels per day |
| Mcf/d | thousand cubic feet per day | $m^3$ | cubic metres |
| MMcf/d | million cubic feet per day | | |
| $m^3$ | cubic metres | | |
| MMbtu | million British Thermal Units | | |
| GJ | gigajoule | | |

Approximately 93 percent of PET's annual production volumes and 96 percent of PET's proved and probable reserves are related to natural gas, and as such the Trust reports production and reserves in Mcf equivalent (Mcfe). Mcfe may be misleading, particularly if used in isolation. In accordance with NI 51-101(as defined herein), a Mcfe conversion ratio for oil of 1 Bbl: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead.

Words importing the singular also include the plural, and *vice versa*, and words importing one gender include all genders. All dollar amounts set forth in the annual information form are in Canadian dollars, except where otherwise indicated.

## CONVERSION

The following table sets forth certain conversions between Standard Imperial Units and the International System of Units (or metric units).

| To Convert From | To | Multiply By |
|---|---|---|
| Mcf | cubic metres | 28.174 |
| cubic metres | cubic feet | 35.494 |
| bbls | cubic metres | 0.159 |
| cubic metres | bbls | 6.293 |
| feet | metres | 0.305 |
| metres | feet | 3.281 |
| miles | kilometres | 1.609 |
| kilometres | miles | 0.621 |
| acres | hectares | 0.405 |
| hectares | acres | 2.471 |
| gigajoules | MMbtu | 0.950 |

## SPECIAL NOTE REGARDING FORWARD-LOOKING INFORMATION AND STATEMENTS

Certain statements contained in the annual information form constitute forward-looking information and statements within the meaning of applicable securities laws. This information and these statements relate to future events or to our future performance. All statements other than statements of historical fact may be forward-looking statements. The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook", "guidance", "objective", "plans", "intends", "targeting", "could", "potential", "outlook", "strategy" and any similar expressions are intended to identify forward-looking information and statements.
In particular, but without limiting the foregoing, this annual information form contains forward-looking information and statements pertaining to the following:

- the quantity and recoverability of PET's reserves;
- the timing and amount of future production;

- future prices as well as supply and demand for natural gas and oil;
- the existence, operations and strategy of the commodity price risk management program;
- the approximate amount of forward sales and hedging to be employed, and the value of financial forward natural gas contracts;
- funds flow sensitivities to commodity price, production, foreign exchange and interest rate changes;
- operating, G&A, and other expenses;
- cash distributions, and the funding and tax treatment thereof;
- amount of future abandonment and reclamation costs, asset retirement and environmental obligations;
- the use of exploration and development activity, prudent asset management, and acquisitions to sustain, replace or add to reserves and production or expand the Trust's asset base;
- the Trust's acquisition strategy and the existence of acquisition opportunities, the criteria to be considered in connection therewith and the benefits to be derived therefrom;
- PET's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets;
- expected book value and related tax value of the Trust's assets and prospect inventory and estimates of net asset value;
- ability to fund distributions and exploration and development;
- expectations regarding PET's access to capital to fund its acquisition, exploration and development activities;
- the transition to IFRS and its impact on the Trust's financial results;
- expected realization of gas over bitumen royalty adjustments;
- future income tax and its effect on funds flow and distributions;
- intentions with respect to preservation of tax pools of and taxes payable by the Trust;
- funding of and anticipated results from capital expenditure programs;
- renewal of and borrowing costs associated with the credit facility;
- future debt levels, financial capacity, liquidity and capital resources;
- future contractual commitments;
- drilling, completion, facilities and construction plans;
- the impact of Canadian federal and provincial governmental regulation on the Trust relative to other issuers;
- Crown royalty rates;
- PET's treatment under governmental regulatory regimes;
- business strategies and plans of management, including future changes in the structure of business operations;
- the timing of and approvals required for conversion to a corporation;
- the anticipation benefits of the proposed corporate conversion
- the anticipated dividend payment and amount thereof contemplated to be paid upon completion of the proposed corporate conversion;
- the timing and delivery of the information circular proxy statement and holding of the Unitholder meeting and Unitholder regulatory and court approval of the proposed corporate conversion; and
- the reliance on third parties in the industry to develop and expand PET's assets and operations.

The forward-looking information and statements contained in this annual information form reflect several material factors and expectations and assumptions of the Trust including, without limitation, that PET will conduct its operations in a manner consistent with its expectations and, where applicable, consistent with past practice; the general continuance of current or, where applicable, assumed industry conditions; the continuance of existing, and in certain circumstances, the implementation of proposed tax, royalty and regulatory regimes; the ability of PET to obtain equipment, services, and supplies in a timely manner to carry out its activities; the accuracy of the estimates of PET's reserve and resource volumes; the timely receipt of required regulatory approvals; certain commodity price and other cost assumptions; the timing and costs of storage facility and pipeline construction and expansion and the ability to secure adequate product transportation; the continued availability of adequate debt and/or equity financing and funds flow to fund the Trust's capital and operating requirements as needed; and the extent of PET's liabilities.

PET believes the material factors, expectations and assumptions reflected in the forward-looking information and statements are reasonable but no assurance can be given that these factors, expectations and assumptions will prove to be correct. The forward-looking information and statements included in this annual information form are not guarantees of future performance and should not be unduly relied upon. Such information and statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in such forward-looking information or statements including, without limitation:

- volatility in market prices for oil and natural gas products;
- supply and demand regarding PET's products;
- risks inherent in PET's operations, such as production declines, unexpected results, geological, technical, or drilling and process problems;
- unanticipated operating events that can reduce production or cause production to be shut-in or delayed;
- changes in exploration or development plans by PET or by third party operators of PET's properties;
- reliance on industry partners;
- uncertainties or inaccuracies associated with estimating reserves volumes;
- competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance; increased costs;
- incorrect assessments of the value of acquisitions;
- increased debt levels or debt service requirements;
- industry conditions including fluctuations in the price of natural gas and related commodities;
- royalties payable in respect of PET's production;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- the need to obtain required approvals from regulatory authorities;
- changes in laws applicable to the Trust, royalty rates, or other regulatory matters;
- general economic conditions in Canada, the United States and globally;
- stock market volatility and market valuations;
- limited, unfavourable, or a lack of access to capital markets, and

certain other risks detailed from time to time in PET's public disclosure documents including, without limitation, those risks and contingencies described above and under ''**RISK FACTORS**" in this annual information form and under ''**RISK FACTORS**" in the Trust's management's discussion and analysis for the year ended December 31, 2009, which will be available on our website at www.paramountenergy.com as well as at www.sedar.com and at www.sec.gov. The foregoing list of risk factors should not be considered exhaustive.

The forward-looking information and statements contained in this annual information form speak only as of the date of this annual information form, and none of the Trust or its subsidiaries assumes any obligation to publicly update or revise them to reflect new events or circumstances, unless expressly required to do so by applicable securities laws

## NON-GAAP MEASURES

Management uses funds flow from operations before changes in non-cash working capital, reduction in gas over bitumen royalty adjustment liability, asset retirement expenditures and certain exploration costs ("funds flow"), funds flow per Trust Unit and annualized funds flow to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore it may not be comparable to the calculation of similar measures for other entities. A reconciliation of funds flow to cash flow from operating activities is presented in our management's discussion and analysis. We use the term "funds flow" as an indicator of financial performance because the term "funds flow" is commonly utilized by investors to evaluate royalty trusts and income funds in the oil and gas sector.

## PARAMOUNT ENERGY TRUST STRUCTURE

Paramount Energy Trust ("**PET**", the "**Trust**", "**us**", "**we**" or "**our**" and, where the context requires, also includes our subsidiaries) is an unincorporated trust established on June 28, 2002 under the laws of the province of Alberta under a trust indenture among Computershare Trust Company of Canada as trustee (the "**Trustee**"), BMO Nesbitt Burns Inc. and Paramount Energy Operating Corp. (the "**Administrator**"). This trust indenture was subsequently amended and restated effective as of August 1, 2002 (the "**Trust Indenture**"). Our assets consist primarily of the POT Royalty (defined below), certain debt owing by Paramount Operating Trust ("**POT**") to us, 100 percent ownership of the Administrator and 100 percent ownership of the beneficial interest in POT.

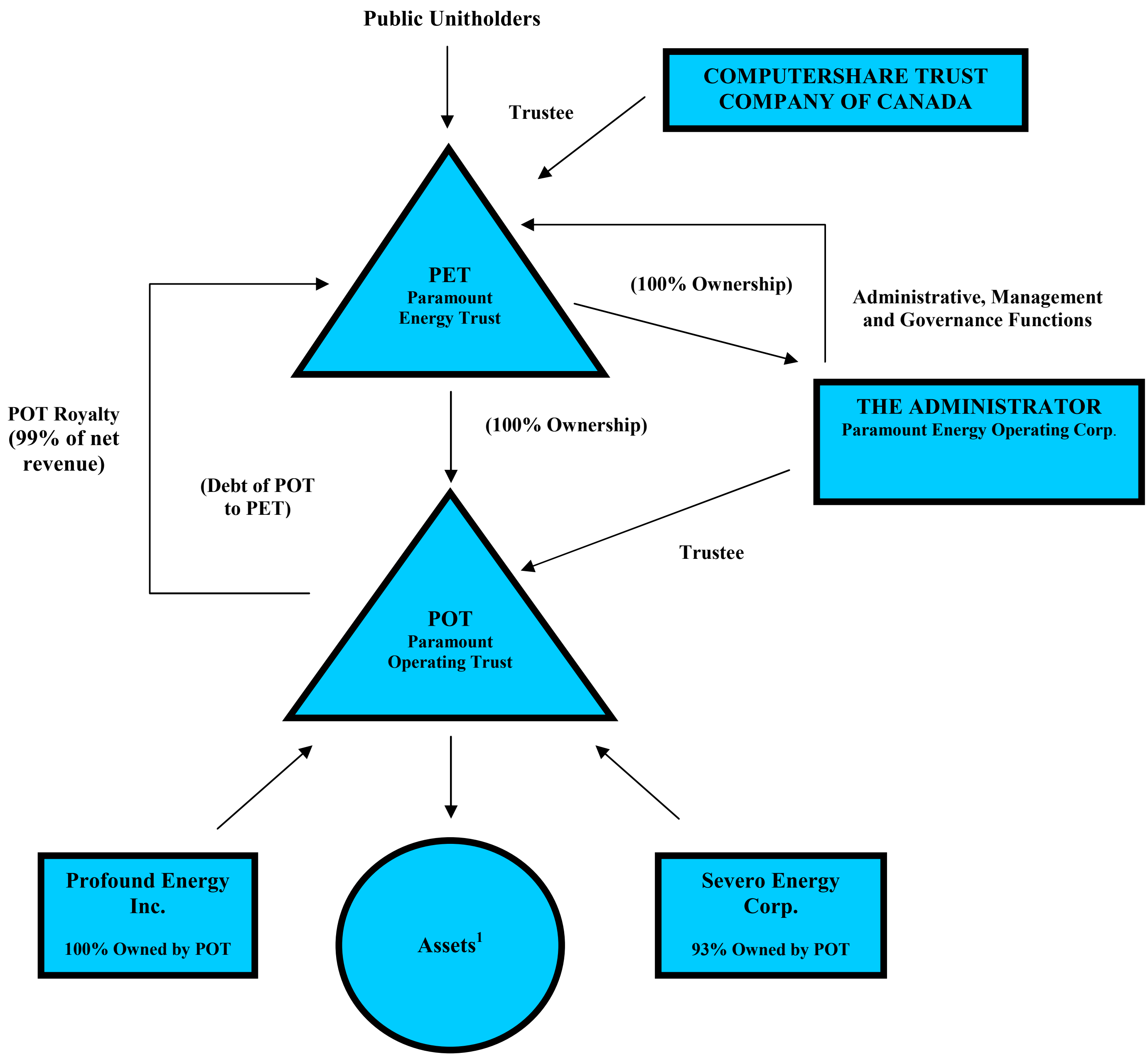
We were established for the purposes of issuing trust units ("**Trust Units**") and acquiring and holding royalties and other investments including the entire beneficial interest in POT and the POT Royalty (defined below). We effectively finance the operations of POT. We make cash distributions to holders of Trust Units ("**Unitholders**"). These distributions are comprised of royalty and interest income from POT, if any, less any expenses and any other amounts that must be withheld or paid to third parties. All Trust Units outstanding from time to time are entitled to an equal undivided share of any distributions. Under the Trust Indenture, we have broad powers to invest funds that are not distributed to Unitholders.

POT is an unincorporated trust established on June 28, 2002 under the laws of the province of Alberta under a trust indenture between the Administrator as trustee and CIBC World Markets Inc. as settlor with PET as its sole beneficiary. This trust indenture was subsequently amended and restated effective as of August 1, 2002 (the "**POT Indenture**"). POT holds, directly and indirectly, all of the oil and natural gas properties in the trust structure on PET's behalf. POT's business is acquiring, exploring, developing, producing, optimizing and disposing of oil and natural gas properties. Under an agreement between POT as grantor and PET as royalty owner (the "**POT Royalty Agreement**"), POT pays PET 99 percent of POT's net revenue from its oil and natural gas properties less permitted deductions with respect to debt payments, capital expenditures and certain other amounts (the "**POT Royalty**").

The Administrator was incorporated on June 28, 2002 under the *Business Corporations Act* (Alberta) ("**ABCA**"). All of the issued and outstanding shares of the Administrator are held in the name of the Trustee for our benefit and on our behalf. The Administrator was formed primarily to act as trustee of POT and to administer, manage and operate the oil and gas business of POT. In addition, the Trustee has, in accordance with the Trust Indenture, delegated to the Administrator the significant management, administrative and governance functions with respect to PET. Much like a traditional oil and gas corporation, only costs incurred by or on behalf of the Administrator to operate the business will ultimately be borne by the Unitholders.

The head offices of PET, POT and the Administrator are located at 3200, 605 – 5 Avenue S.W., Calgary, Alberta. The Administrator's registered office is located at 3200, 605 – 5 Avenue S.W., Calgary, Alberta.

The following diagram illustrates the current organizational structure of PET including the material operating subsidiaries of the Trust, the flow of funds from those operating subsidiaries to the Trust and the percentage of voting securities owned:




**Note:**
Our assets are directly held by POT and several corporations and partnerships. POT and Profound Energy Inc. are PET's principal subsidiaries, each holding total assets that exceed 10 percent of our total consolidated assets or revenues as at and for the year ended December 31, 2009.

## GENERAL DEVELOPMENT OF THE BUSINESS

### Three Year History

The following is a description of the general development of the business of the Trust, including acquisitions, equity issues and convertible debenture financings, over its last three completed financial years.

***Year Ended December 31, 2007***

Craigend/Radway/Stry Acquisition

The Craigend/Radway/Stry acquisition closed on April 30, 2007 for a purchase price of $45.2 million, and included 5 MMcf/d of shallow natural gas production as well as significant drilling and recompletion prospects and cost reduction opportunities through facility consolidation.

Birchwavy Acquisition

On June 26, 2007, PET completed a significant acquisition of natural gas producing properties in central Alberta (the **"Birchwavy Acquisition"**) for a purchase price of $392 million. The acquired assets were technically and operationally similar to PET's base assets and offer year-round access, high working interests, operatorship and infrastructure ownership.

Equity Issue and Convertible Debenture Financing

In conjunction with the Birchwavy Acquisition, PET completed an issue on June 20, 2007 by way of short form prospectus of 20,450,000 subscription receipts at a price of $12.25 per subscription receipt for gross proceeds of $250,512,500 and $75,000,000 aggregate principal amount of 6.50% convertible extendible unsecured subordinated debentures (the "**6.50% Convertible Debentures"**) with a conversion price of $14.20 per Trust Unit.

Minor Consolidation Acquisition

PET closed a minor consolidating acquisition in northeast Alberta on June 28, 2007 for a purchase price of $14 million. This acquisition included 0.7 MMcf/d with an additional 2 MMcf/d of shut-in natural gas production for which PET receives monthly royalty credits as part of the gas over bitumen financial solution. (See "**REGULATORY RULINGS – GAS OVER BITUMEN").**

Trust Tax Legislation

On June 22, 2007, new legislation was passed (the **"Trust Tax Legislation"**) pursuant to which, certain distributions will be subject to at trust-level tax, and will be characterized as dividends to the Unitholders, commencing January 1, 2011 (provided that PET only experiences "normal growth" and no "undue expansion" before then).Once the Trust Tax Legislation becomes applicable to PET, distributions to PET's Unitholders will no longer be deductible in computing trust taxable income. In conjunction with the trust level tax, the personal tax on distributions will be similar to the tax paid on a dividend received from a taxable Canadian corporation. This will effectively reduce the income available for distribution to PET's Unitholders. with the end result being a two-tiered tax structure similar to that of corporations and the double taxation of distributions for Unitholders who hold their Trust Units in registered accounts such as RRSP, RRIF, RESP, DPSP and TFSA accounts.

On March 4, 2009 legislation was passed providing that the provincial component of the tax on PET is to be calculated based on the general provincial rate in each province in which PET has a permanent establishment.

Under the Provincial SIFT Tax Amendments PET is considered to have a permanent establishment in Alberta, where the provincial tax rate in 2011 is expected to be ten percent, which would result in an effective tax rate of 26.5 percent in 2011 and 25 percent in 2012. This is the same way that a corporation would calculate its provincial tax rate. The provincial component of the tax was substantively enacted as of December 31, 2009 for financial statement purposes.

***Year Ended December 31, 2008***

In 2008 the Trust disposed of certain non-core assets and royalty interests in central and southern Alberta and Saskatchewan for proceeds totalling $24.2 million. The disposed properties represented approximately 2.4 MMcf/d of daily production and 0.6 MMcf/d of deemed shut-in production, as well as 5.0 Bcfe of proved and probable reserves.

***Year Ended December 31, 2009***

Dispositions

PET disposed of non-core assets Athabasca and Saskatchewan for net proceeds of $26.6 million, representing approximately 5.2 MMcf/d of daily production, as well as 12.7 Bcfe of proved and probable reserves.

Legend Shut in

Effective October 31, 2009 the Energy Resources Conservation Board ("ERCB") ordered the shut-in of approximately 8.6 MMcf/d of natural gas production from the Trust's Legend property due to gas over bitumen concerns. An additional 1.9 MMcf/d has been shut-in due to the shut in of facilities in the area. As a result of the ERCB order, 12.6 Bcfe of proved reserves related to the Legend property were reclassified to probable by PET's reserve evaluators. PET believes it is eligible to receive the gas over bitumen financial solution in respect of the production by the ERCB order, as prescribed by the royalty regulations enacted by the Alberta government (see "REGULATORY RULINGS – GAS OVER BITUMEN").

Alberta drilling incentive program

On March 3, 2009 the Government of Alberta announced a new incentive program designed to increase industry activity despite low oil and natural gas prices and tightened credit markets caused by the global financial crisis at that time. The program was effective commencing April 1, 2009, and offers two separate incentives:

- A $200 per metre drilling royalty credit for new conventional oil and natural gas wells, which will be available to companies until April 1, 2011 on a sliding scale based on company production levels from 2008.
- A maximum five percent royalty rate for the first year of production from new oil or gas wells. The maximum rate would apply to all wells which begin production after March 31, 2009 and before April 1, 2011.

PET received drilling credits totalling $1.6 million in respect of 2009 drilling activity.

Profound Acquisition

On June 30, 2009, pursuant to a takeover offer announced on March 31, 2009, the conversion of previously issued special warrants and open market purchases, PET acquired 67.3 percent of the outstanding common shares and thereby gained control of Profound Energy Inc. ("Profound"). On August 13, 2009, PET completed the second stage of the announced transaction, acquiring the remaining 32.7 percent of Profound's outstanding shares. Cash consideration paid for Profound consisted of $6.9 million for the special warrants, $3.1 million for the open market share purchases and $14.2 million for the tendered shares on June 30, 2009 and August 13, 2009, and $3.3 million of acquisition costs for a total of $27.5 million. In addition, PET issued 10 million Trust Units to Profound shareholders valued at $32.2 million, using PET's weighted average unit trading price for the five trading days surrounding the announcement date of $3.21 per Trust Unit.

On August 13, 2009 a wholly owned subsidiary of PET amalgamated with Profound. The company resulting from the amalgamation (also named "Profound Energy Inc.") is now an indirect wholly-owned subsidiary of PET. The Profound transaction resulted in the acquisition of certain assets located primarily in west central Alberta, affording deep basin-style resource play opportunities and exposure to development of the Pembina area tight Cardium oil play.

Convertible Debenture Amendments

Pursuant to an extraordinary resolution passed by the holders of the Trust's 2006 6.25 percent convertible debentures (the "**2006 6.25% Convertible Debentures**"), effective December 17, 2009 certain amendments were made to the 2006 6.25% Convertible Debentures (as amended, the "**7.25% Convertible Debentures**"). Those amendments included an increase in the coupon from 6.25 percent to 7.25 percent, the conversion price being reduced to $7.50 per Trust Unit, the maturity date being extended to January 31, 2015, and the non-call period being set at January 31, 2013. The **7.25% Convertible Debentures** are listed and posted for trading on the TSX under the symbol **PMT.DB.D**.

***Recent Developments***

Ukalta Acquisition

On January 7, 2010 PET closed the acquisition ("Ukalta Acquisition") of natural gas assets within the Birchwavy West core area for $18.0 million, including a $1.8 million deposit paid in December 2009.

Conversion

The Board of Directors of Paramount Energy Operating Corp., the Administrator of Pet, unanimously approved the conversion of the trust to a corporation which, subject to approval of PET's Unitholders as well as customary court and regulatory approvals, is anticipated to be completed at the Annual General Meeting of the Trust scheduled for June 17, 2010. The details of the conversion will be contained in an information circular which is anticipated to be mailed to UnitholderUnitholders in May 2010.

The corporate conversion will be subject to receipt of all required regulatory, stock exchange and Court of Queen's Bench of Alberta approvals including approval of at least 66 $^{2/3}$ percent of the votes by Unitholders present in person or by proxy at a meeting of the Trust's Unitholders.

## DESCRIPTION OF THE BUSINESS

### Business Plan

***Summary***

Our business plan is focused on sustainability of our base shallow gas assets and growth through new ventures. The Trust provides Unitholders with an investment vehicle which distributes income and adds value through the exploitation of our current producing assets, low exposure exploration of our undeveloped land base, and prudent acquisitions of additional lands and shallow gas assets. The sustainability focus in our business plan is based on four pillars: Asset Optimization; Funds Flow Maximization; Accretive Acquisitions and Balance Sheet Strength – all directed towards maximization of distributions and Unitholder value.

The Trust is also pursuing multiple new venture opportunities synergistic with our Northeast Alberta assets which include natural gas storage opportunities, bitumen exploitation and coal bed methane potential. In addition the Trust is concentrating on increasing its exposure to higher impact resource-style plays.

In recent years PET has consciously moved to reposition its asset base to enhance its prospect inventory, adding an element of higher impact, growth oriented, and resource-style opportunities to its asset portfolio. In 2008 the Trust successfully added the Elmworth Montney play to its prospect inventory through grass roots exploration, and signed a farmout agreement with an industry partner on these lands in 2009 in order to accelerate development and mitigate exploration risk.

In 2009, PET executed a major step in the strategic expansion of its asset base with the Profound acquisition, to add a component of deep basin, resource-style properties to its asset base as well as to gain exposure to the developing Cardium tight oil play in the Pembina area of Alberta.

Since the Trust's inception, the asset base has undergone significant growth, and diversification, both geographically and with respect to the nature of the opportunities in the prospect inventory for future value creation.

***Asset Optimization and Growth***

The Trust's asset base is comprised of properties in six core areas: Athabasca; Northeast; Birchwavy West; Birchwavy East; West Central; and assets owned by Severo Energy Corp. (in central Alberta). In addition, PET has certain other minor assets in southern Alberta. Most fields are characterized by long production histories with gas wells demonstrating a predictable decline in production as reserves are produced over the years. The assets are comprised of natural gas properties that require relatively low capital reinvestment to offset natural production declines. We anticipate that funds flow from our assets will be sufficient to fund production, administrative expenses, interest expenses and capital expenditures and to permit us to accumulate working capital for our ongoing operations and distributions to Unitholders.

Capital expenditures target workovers, facility optimization activities, completion of secondary objectives in existing well bores, and drilling low risk development and low exposure exploration wells to maximize production and cash flow. Our assets host significant opportunities to add value that fit our relatively conservative definition of acceptable risk. In addition, our significant ownership of processing and transportation facilities and large consolidated acreage position allow us to realize operating synergies and maintain operating costs near their current levels on a per unit production basis. We intend to maximize the value of undeveloped land with opportunities that do not meet our risk/reward hurdles by entering into farm out or other arrangements with third parties under which the third party will provide exploration funding in exchange for an earned interest or by swapping properties for other assets or equity in other entities, or by selling properties.

***Funds Flow Maximization***

Our internal marketing group markets production from our assets with a view to optimizing gas netbacks by seeking the best transportation arrangement and markets. Direct marketing arrangements and pipeline transportation contracts are monitored closely to align actual usage with contractual obligations. We maximize the value of our assets by optimizing the natural gas production while minimizing costs thus maximizing netbacks. A number of the office, technical and field operations staff responsible for operating and managing our current assets have done so for many years.

***Accretive Acquisitions***

In addition to pursuing the acquisition of other properties in our core areas we intend to continue to seek corporate and property acquisition opportunities focused on natural gas. Future acquisition opportunities may lead to additional geographical and/or commodity diversification. The primary objective is the creation of value for Unitholders and, as such, we will target acquisitions that are accretive to net asset value and funds flow per Trust Unit and which increase our reserve and production base on a per Trust Unit basis. We will not limit our acquisitions by commodity or geography. We plan to finance acquisitions through debt and equity financings. We are normally in the process of evaluating several potential acquisitions at any one time which individually or together could be material

We cannot predict whether any current or future opportunities will result in one or more acquisitions being completed.

***Healthy Balance Sheet***

We strive to maintain a healthy balance sheet, recognizing the cyclical nature of commodity prices and the oil and gas business. This prepares us to pursue new opportunities to add value for our Unitholders as they arise throughout the commodity price cycles.

**Business Conditions**

***Industry Competition***

The petroleum and natural gas industry is highly competitive at all levels. We compete with other companies and other energy trusts for all of our business inputs including land and mineral rights, exploitation and development prospects, access to commodity markets, transportation, property and corporate acquisitions, available capital and manpower and equipment. We endeavour to be competitive by maintaining a strong financial position and by utilizing current and new technologies to enhance exploitation, development and operational activities.

***Cyclical and Seasonal Impact***

Our operational results and financial condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors including weather and general economic conditions as well as conditions in other oil and natural gas producing and consuming regions. Any decline in natural gas prices could have a material adverse effect on our financial condition.

***Changes to Contracts***

As of the date of this annual information form we do not anticipate that any aspect of our business will be materially affected in the current fiscal year by the renegotiation or termination of contracts or subcontracts with except of those material contracts that are required to be amended as a result of the Trust's conversion to a corporation. The Trust does not anticipate that any of these changes will have a material effect.

***Employees***

As of December 31, 2009 the Administrator had 286 full and part-time permanent employees for the purposes of operating POT's natural gas operations and rendering administrative services to PET.

## STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION

The reserves data and other oil and gas information presented in this section is stated in accordance with Form 51-101F1. All of our reserves are in Canada and, specifically, in the provinces of Alberta and Saskatchewan. Approximately 96 percent of our reserves are conventional natural gas.

The Report of Management and Directors on Oil and Gas Disclosure in Form 51-101F3 and the two Reports on Reserves Data by McDaniel & Associates Ltd. ("**McDaniel**") in Form 51-101F2 (the "**McDaniel Reports**") are attached as Appendices "**B**", "**C**" and "**D**" respectively to this annual information form.

**Disclosure of Reserves Data**

McDaniel performed evaluations of 100 percent of the Trust's properties, the results of which are included in the McDaniel Reports, with a preparation date of February 9, 2010. The effective date of the McDaniel Reports is December 31, 2009. The McDaniel Reports summarize the natural gas reserves and the net present values of future net revenue for these reserves using forecast prices and costs of PET and Severo.

The reserves data set forth below (the "**Reserves Data**") is based upon the summation of the McDaniel Reports**.** The Reserves Data conforms with the requirements of National Instrument 51-101 *Standards of Disclosure for Oil and Gas Activities* ("**NI 51-101**"). We engaged McDaniel to provide an evaluation of proved and proved and probable reserves and no attempt was made to evaluate possible reserves.

The Reserves Data includes the estimated future net revenue to the Government of Alberta royalty adjustments for our reserves which have been shut-in as a result of the gas over bitumen issue as per the amendments to the Royalty

Regulation. The Reserves Data also includes the estimated future net revenue attributed to the reserves which have been shut-in or denied production as a result of the gas over bitumen issue if they were to recommence production. These reserves have all been classified as probable reserves and for the purposes of this additional valuation, McDaniel has assumed that these reserves will recommence production in the year 2013 or 2014 and will be subject to an additional 10 percent gross overriding royalty payable to the Crown. (See "**REGULATORY RULINGS – GAS OVER BITUMEN, RISK FACTORS** and **GOVERNMENT REGULATION")**.

With the enactment of trust tax legislation (see **GENERAL DEVELOPMENT OF THE BUSINESS - Trust Tax Legislation*)*** PET is now required to present the net present values of future net revenue on an after-tax basis. The McDaniel Reports assume the utilization of PET's current existing tax pools plus additions from future development costs assumed in the McDaniel Reports, beginning in 2009 with taxation of after-tax cash flow at corporate income tax rates beginning in 2011. Actual future results for the Trust will differ materially from the assumptions mandated by National Instrument 51-101, as PET operates its business as a 'going-concern' and the McDaniel Reports only represent a 'produce-out' analysis of cash flows. In addition the Trust has an extensive prospect inventory to add production, reserves and cash flows beyond that recognized in the NI 51-101 compliant McDaniel Reports.

**It should not be assumed that the estimates of future net revenues presented in the tables below represent the fair market value of the reserves. There is no assurance that the forecast prices and costs assumptions will be attained and variances could be material. Actual natural gas reserves may be greater than or less than the estimates provided in this Reserves Statement.**

***Reserves Data (Forecast Prices and Costs)***

**SUMMARY OF RESERVES**
**TOTAL RESERVES**
**as at December 31, 2009**
**FORECAST PRICES AND COSTS**

| | Light and Medium Crude | | Heavy Oil | | Natural Gas | | Natural Gas Liquids | | Natural Gas Equivalent | |
|---|---|---|---|---|---|---|---|---|---|---|
| **RESERVES CATEGORIES** | **Gross (Mbbl)** | **Net (Mbbl)** | **Gross (Mbbl)** | **Net (Mbbl)** | **Gross (MMcf)** | **Net (MMcf)** | **Gross (Mbbl)** | **Net (Mbbl)** | **Gross (MMcfe)** | **Net (MMcfe)** |
| **Proved Producing** | 616 | 518 | 406 | 371 | 190,503 | 164,447 | 743 | 497 | 201,094 | 172,762 |
| **Proved Non-Producing** | 16 | 15 | 7 | 5 | 7,808 | 6,709 | 58 | 37 | 8,293 | 7,051 |
| **Proved Undeveloped** | 78 | 54 | - | - | 31,018 | 27,431 | 306 | 196 | 33,322 | 28,932 |
| **Total Proved** | 710 | 587 | 413 | 376 | 229,330 | 198,587 | 1,107 | 730 | 242,709 | 208,745 |
| **Total Probable** | 335 | 267 | 180 | 162 | 219,840 | 181,497 | 607 | 388 | 226,574 | 186,396 |
| **Proved and Probable** | 1,045 | 854 | 593 | 538 | 449,170 | 380,084 | 1,714 | 1,118 | 469,283 | 395,141 |

**NET PRESENT VALUE OF FUTURE NET REVENUE**
**BEFORE TAX**
**as at December 31, 2009**
**FORECAST PRICES AND COSTS ($millions)**

| | Before Income Taxes Discounted at (%) | | | | | UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/Mcfe) |
|---|---|---|---|---|---|---|
| **RESERVES CATAGORIES** | **0%** | **5%** | **10%** | **15%** | **20%** | |
| **Proved Producing** | $ 914 | $ 764 | $ 664 | $ 591 | $535 | $ 3.30 |
| **Proved Non-Producing** | 18 | 14 | 12 | 10 | 9 | 1.44 |
| **Proved Undeveloped** | 77 | 56 | 41 | 30 | 23 | 1.23 |
| **Total Proved** | 1,009 | 835 | 717 | 632 | 567 | 2.96 |
| **Total Probable** | 827 | 553 | 392 | 291 | 224 | 1.73 |
| **Proved and Probable** | $ 1,836 | $ 1,387 | $ 1,110 | $ 923 | $ 791 | $ 2.36 |

**NET PRESENT VALUE OF FUTURE NET REVENUE**
**AFTER TAX**
**as at December 31, 2009**
**FORECAST PRICES AND COSTS ($millions)**

| | After Income Taxes Discounted at (%) | | | | | UNIT VALUE AFTER INCOME TAX DISCOUNTED AT 10%/year ($/Mcfe) |
|---|---|---|---|---|---|---|
| **RESERVES CATAGORIES** | **0%** | **5%** | **10%** | **15%** | **20%** | |
| **Proved Producing** | $ 832 | $ 695 | $ 605 | $ 540 | $ 491 | $ 3.01 |
| **Proved Non-Producing** | 14 | 11 | 9 | 8 | 7 | 1.08 |
| **Proved Undeveloped** | 57 | 40 | 28 | 20 | 14 | 0.84 |
| **Total Proved** | 903 | 746 | 642 | 568 | 511 | 2.65 |
| **Total Probable** | 628 | 414 | 291 | 214 | 163 | 1.28 |
| **Proved and Probable** | $ 1531 | $ 1,160 | $ 933 | $ 781 | $ 674 | $ 1.99 |

**FUTURE NET REVENUE**
**TOTAL RESERVES (UNDISCOUNTED)**
**as at December 31, 2009**
**FORECAST PRICES AND COSTS ($millions)**

| Reserves Category | Revenue | Royalties | Gas over Bitumen Royalty Adjustments | Operating Costs | Development Costs | Abandonment and Reclamation Costs | Future Net Revenue After Costs Before Income Taxes | Income Taxes | Future Net Revenue after Income Taxes |
|---|---|---|---|---|---|---|---|---|---|
| **Proved Reserves** | $ 1,920 | $ (263) | $ 130 | $ (594) | $ (75) | $ (109) | $ 1,009 | $ (106) | $ 903 |
| **Proved and Probable Reserves** | $ 3,888 | $ (591) | $ 130 | $ (1,197) | $ (256) | $ (138) | $ 1,836 | $ (305) | $ 1,531 |

**FUTURE NET REVENUE**
**TOTAL RESERVES**
**by production type**
**as at December 31, 2009**

| RESERVES CATEGORY | Production Group | Future Net Revenue Before Income Taxes (discounted at 10%/year) ($millions) | Unit Value ($/Mcfe) ($/bbl) |
|---|---|---|---|
| **Proved Reserves** | Natural Gas and NGL (including by-products but excluding solution gas from wells) | $ 679 | $ 2.98 |
| **Proved Reserves** | Light and Medium Crude Oil (including solution gas and other by-products) | 26 | 37.44 |
| **Proved Reserves** | Heavy Oil (including solution gas and other by-products) | 12 | 29.21 |
| **Proved Reserves - Total** | | **$ 717** | **$ 2.95** |
| **Proved and Probable Reserves** | Natural Gas and NGL (including by-products but excluding solution gas from wells) | $ 1,058 | $ 2.37 |
| **Proved and Probable Reserves** | Light and Medium Crude Oil (including solution gas and other by-products) | 36 | 34.97 |
| **Proved and Probable Reserves** | Heavy Oil (including solution gas and other by-products) | 16 | 27.70 |
| **Proved and Probable Reserves - Total** | | **$ 1,110** | **$ 2.37** |

**FORECAST PRICES AND COSTS ($MILLIONS)**

***Pricing Assumptions (Forecast Prices and Costs)***

The forecast cost and price assumptions assume variations in wellhead selling prices and take into account inflation with respect to future operating and capital costs. Natural gas benchmark reference pricing, as at December 31, 2009, inflation and exchange rates utilized by McDaniel in the McDaniel Reports, which were McDaniel's then current forecasts at the date of the McDaniel Reports, were as follows:

**SUMMARY OF PRICING ASSUMPTIONS**
**as at December 31, 2009**
**FORECAST PRICES AND COSTS**

| Forecast | West Texas Intermediate Crude Oil ($US/bbl) | Edmonton Light Crude Oil ($Cdn/bbl) | Natural Gas at AECO ($Cdn/GJ) | Foreign Exchange ($US/$Cdn) (1) |
|---|---|---|---|---|
| 2010 | 80.00 | 83.20 | 6.05 | 0.950 |
| 2011 | 83.60 | 87.00 | 6.75 | 0.950 |
| 2012 | 87.40 | 91.00 | 7.15 | 0.950 |
| 2013 | 91.30 | 95.00 | 7.45 | 0.950 |
| 2014 | 95.30 | 99.20 | 7.80 | 0.950 |
| 2015 | 99.40 | 103.50 | 8.15 | 0.950 |
| 2016 | 101.40 | 105.60 | 8.40 | 0.950 |
| 2017 | 103.40 | 107.70 | 8.55 | 0.950 |

| Forecast | West Texas Intermediate Crude Oil ($US/bbl) | Edmonton Light Crude Oil ($Cdn/bbl) | Natural Gas at AECO ($Cdn/GJ) | Foreign Exchange ($US/$Cdn) (1) |
|---|---|---|---|---|
| 2018 | 105.40 | 109.80 | 8.70 | 0.950 |
| 2019 | 107.60 | 112.10 | 8.90 | 0.950 |
| 2020 | 109.70 | 114.30 | 9.05 | 0.950 |
| 2021 | 111.90 | 116.50 | 9.25 | 0.950 |
| 2022 | 114.10 | 118.80 | 9.45 | 0.950 |
| 2023 | 116.40 | 121.20 | 9.65 | 0.950 |
| Thereafter | 2% | 2% | 2% | 0.950 |

Exchange rates used to generate the benchmark reference prices in this table.

For comparison purposes, the Trust realized a weighted average gas price for the year ended December 31, 2009 of $7.27/Mcfe for natural gas. The weighted average AECO daily gas price for the same 12 month period was $3.98/Mcf.

***Definitions and Other Notes***

Columns and rows may not add due to rounding.

The crude oil, natural gas liquids and natural gas reserve estimates presented in the McDaniel Reports are based on the definitions and guidelines contained in the COGE Handbook and NI 51-101. A summary of those definitions are set forth below.

"**COGE Handbook**" means the Canadian Oil and Gas Evaluation Handbook prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society) as amended from time to time;

"**Development costs**" means costs incurred to obtain access to reserves and to provide facilities for extracting, treating, gathering and storing the oil and gas from the reserves. More specifically, development costs, including applicable operating costs of support equipment and facilities and other costs of development activities, are costs incurred to:

(a) gain access to and prepare well locations for drilling, including surveying well locations for the purpose of determining specific development drilling sites, clearing ground, draining, road building, and relocating public roads, gas lines and power lines, to the extent necessary in developing the reserves;

(b) drill and equip development wells, development type stratigraphic test wells and service wells, including the costs of platforms and of well equipment such as casing, tubing, pumping equipment and wellhead assembly;

(c) acquire, construct and install production facilities such as flow lines, separators, treaters, heaters, manifolds, measuring devices and production storage tanks, natural gas cycling and processing plants, and central utility and waste disposal systems; and

(d) provide improved recovery systems.

"**Exploration costs**" means costs incurred in identifying areas that may warrant examination and in examining specific areas that are considered to have prospects that may contain oil and gas reserves, including costs of drilling exploratory wells and exploratory type stratigraphic test wells. Exploration costs may be incurred both before acquiring the related property and after acquiring the property. Exploration costs, which include applicable operating costs of support equipment and facilities and other costs of exploration activities, are:

(a) costs of topographical, geochemical, geological and geophysical studies, rights of access to properties to conduct those studies, and salaries and other expenses of geologists, geophysical crews and others conducting those studies;

(b) costs of carrying and retaining unproved properties, such as delay rentals, taxes (other than income and capital taxes) on properties, legal costs for title defence, and the maintenance of land and lease records;
(d) dry hole contributions and bottom hole contributions;
(e) costs of drilling and equipping exploratory wells; and
(f) costs of drilling exploratory type stratigraphic test wells.

"**Gross**" means:

(a) in relation to our interest in production and reserves, our "**Trust Gross Reserves**", which are our working interest (operating and non-operating) share before deduction of royalties and without including any royalty interest;
in relation to wells, the total number of wells in which we have an interest; and
in relation to properties, the total area of properties in which we have an interest.

"**Net**" means:

(a) in relation to our interest in production and reserves, our working interest (operating and non-operating) share after deduction of royalties obligations, plus our royalty interest in production or reserves.
in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
in relation to our interest in a property, the total area in which we have an interest multiplied by the working interest owned by us.

***Reserve Categories***

Reserves are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, from a given date forward, based on

- analysis of drilling, geological, geophysical and engineering data;
- the use of established technology; and
- specified economic conditions.

Reserves are classified according to the degree of certainty associated with the estimates.

(a) **Proved reserves** are those reserves that can be estimated with a high degree of certainty to be recoverable. It is likely that the actual remaining quantities recovered will exceed the estimated proved reserves.
**Probable reserves** are those additional reserves that are less certain to be recovered than proved reserves. It is equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated proved and probable reserves.

Other criteria that must also be met for the categorization of reserves are provided in the COGE Handbook.

Each of the reserve categories (proved and probable) may be divided into developed and undeveloped categories:

(a) **Developed reserves** are those reserves that are expected to be recovered from existing wells and installed facilities or, if facilities have not been installed, that would involve a low expenditure (for example, when compared to the cost of drilling a well) to put the reserves on production. The developed category may be subdivided into producing and non-producing.
(b) **Developed producing reserves** are those reserves that are expected to be recovered from completion intervals open at the time of the estimate. These reserves may be currently producing or, if shut-in, they must have previously been on production, and the date of resumption of production must be known with reasonable certainly.

(c) **Developed non-producing reserves** are those reserves that either have not been on production, or have previously been on production, but are shut-in, and the date of resumption of production is unknown.

(d) **Undeveloped reserves** are those reserves expected to be recovered from known accumulations where a significant expenditure (for example, the cost of drilling a well) is required to render them capable of production. They must fully meet the requirements of the reserves classification (proved, probable) to which they are assigned.

***Levels of Certainty for Reported Reserves***

The qualitative certainty levels referred to in the definitions above are applicable to individual reserve entities (which refers to the lowest level at which reserves calculations are performed) and to reported reserves (which refers to the highest level sum of individual entity estimates for which reserves are presented). Reported reserves should target the following levels of certainty under a specific set of economic conditions:

at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated proved and probable reserves.

Additional clarification of certainty levels associated with reserves estimates and the effect of aggregation is provided in the COGE Handbook.

**Reconciliations of Changes in Reserves and Future Net Revenue**

**RECONCILIATION OF TRUST GROSS RESERVES**
**TOTAL RESERVES (1)**
**FORECAST PRICES AND COSTS**

| | Gross Proved | | | | Gross Probable | | | | Gross Proved + Probable | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **FACTORS** | **Oil MMbbl** | **Gas Bcf** | **Liquids MMbbl** | **Gas Equivalent Bcfe** | **Oil MMbbl** | **Gas Bcf** | **Liquids MMbbl** | **Gas Equivalent Bcfe** | **Oil MMbbl** | **Gas Bcf** | **Liquids MMbbl** | **Gas Equivalent Bcfe** |
| December 31, 2009 (2) | 0.6 | 257.5 | 0.0 | 261.0 | 0.3 | 220.7 | 0.0 | 222.7 | 0.9 | 478.2 | 0.0 | 483.7 |
| Improved Recoveries, Extensions and Discoveries(3) | 0.0 | 10.8 | 0.0 | 11.1 | 0.0 | 2.9 | 0.0 | 3.1 | 0.0 | 13.7 | 0.0 | 14.2 |
| Technical Revisions | 0.0 | (2.1) | (0.0) | (1.9) | (0.0) | (9.3) | (0.0) | (9.5) | (0.2) | (67.2) | (0.1) | (68.9) |
| Acquisitions | 0.7 | 32.4 | 1.1 | 43.4 | 0.2 | 14.2 | 0.6 | 19.1 | 0.9 | 46.6 | 1.7 | 62.4 |
| Dispositions | (0.0) | (10.8) | - | (10.8) | - | (5.8) | - | (5.8) | (0.0) | (16.7) | - | (16.7) |
| Production | (0.2) | (56.0) | (0.1) | (57.6) | - | - | - | - | (0.0) | (0.1) | (0.0) | (0.1) |
| Economic Factors | 0.0 | (2.5) | - | (2.5) | (0.0) | (2.9) | - | (2.9) | 0.0 | (5.4) | - | (5.4) |
| December 31, 2010 | 1.1 | 229.3 | 1.1 | 242.7 | 0.5 | 219.8 | 0.6 | 226.6 | 1.6 | 449.2 | 1.7 | 469.3 |

Includes reserves from zones not affected by gas over bitumen issue and reserves shut-in pursuant to AEUB decisions and orders described under the heading (See "**REGULATORY RULINGS - GAS OVER BITUMEN.** See also **RISK FACTORS** and **GOVERNMENT REGULATION**").

(1) The opening balance on December 31, 2009 includes all of our reserves, including reserves that were shut-in or identified for shut-in as a result of the gas over bitumen issue. At December 31, 2009 and 2010 all reserves shut-in as a result of the gas over bitumen issue were categorized as probable reserves.

(2) The Trust includes all reserve additions resulting from capital expenditures in Extensions, Improved Recoveries and Discoveries.

## Additional Information Relating to Reserves Data

### *Undeveloped Reserves*

The following table discloses, for each product type, the volumes of proved undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

| Year | Light and Medium Oil (Mbbl) | | Heavy Oil (Mbbl) | | Natural Gas (MMcf) | | NGLs (Mbbl) | |
|---|---|---|---|---|---|---|---|---|
| | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End |
| **Prior thereto** | - | - | - | - | 4,700 | - | - | - |
| **2007** | 137 | 20 | - | - | 41,070 | 24,492 | - | - |
| **2008** | - | - | - | - | 159 | - | - | - |
| **2009** | 78 | 78 | - | - | 6,509 | 6,509 | 306 | 306 |

The Trust has a large inventory of proved undeveloped reserves. Poor gas prices in 2009 deferred activity on these reserves. These reserves are booked as per the COGE handbook to company land immediately adjacent to existing producing wells. The Trust plans to develop these reserves over the next 5 to 6 years as part of larger drilling programs. The Trust uses many factors to determine its annual budgets and all projects, booked and unbooked, compete based on these factors with funds balanced to maximize returns from capital investments as well as drive strategic initiatives.

The following table discloses, for each product type, the volumes of probable undeveloped reserves that were first attributed in each of the most recent three financial years and, in the aggregate, before that time.

| Year | Light and Medium Oil (Mbbl) | | Heavy Oil (Mbbl) | | Natural Gas (MMcf) | | NGLs (Mbbl) | |
|---|---|---|---|---|---|---|---|---|
| | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End | First Attributed | Cumulative at Year End |
| **Prior thereto** | - | - | - | - | 3,562 | 4,467 | - | - |
| **2007** | 35 | 25 | - | - | 90,465 | 71,517 | - | - |
| **2008** | - | 20 | - | - | 9,246 | 0 | - | - |
| **2009** | 29 | 29 | - | - | 10,082 | 10,082 | 269 | 269 |

The Trust has a large inventory of proved and probable undeveloped reserves primarily on its Viking resource play in east central Alberta. New wells typically experience rapid production declines within the first 12 months of production and therefore a significant percent of the well's revenue is generated very early in its productive life. Poor gas prices in 2009 deferred activity on these reserves. These reserves are booked as per the COGE handbook to company lands. The Trust plans to develop these reserves over the next 8 to 9 years as part of larger drilling programs. As stated above, the Trust uses many factors to determine its annual budgets and all projects, booked and unbooked, compete based on these factors for a limited pool of capital funds.

### *Significant Factors or Uncertainties*

The process of estimating reserves is complex. It requires significant judgments and decisions based on available geological, geophysical, engineering, and economic data. These estimates may change substantially as additional data from ongoing development activities and production performance becomes available and as economic conditions impacting oil and gas prices and costs change. The reserves estimates contained herein are based on current production forecasts, prices and economic conditions.

As circumstances change and additional data become available, reserve estimates also change. Estimates made are reviewed and revised, either upward or downward, as warranted by the new information. Revisions are often required due to changes in well performance, prices, economic conditions and governmental restrictions.

Although every reasonable effort is made to ensure that reserve estimates are accurate, reserve estimation is an inferential science. As a result, the subjective decisions, new geological, geophysical or production information and a changing environment may impact these estimates. Revisions to reserve estimates can arise from changes in year-end oil and gas prices, and reservoir performance. Such revisions can be either positive or negative**.**

***Future Development Costs***

The following table sets forth development costs deducted in the estimation of our future net revenue attributable to the reserve categories noted below.

| | **FUTURE DEVELOPMENT COSTS FORECAST PRICES AND COSTS ($millions)** | | | |
|---|---|---|---|---|
| **Year** | **Proved Reserves** | | **Proved And Probable Reserves** | |
| | **0%** | **10%** | **0%** | **10%** |
| **2010** | 11.9 | 11.4 | 16.9 | 16.1 |
| **2011** | 14.8 | 12.8 | 38.1 | 33.0 |
| **2012** | 17.3 | 13.7 | 32.6 | 25.7 |
| **2013** | 18.5 | 13.3 | 22.3 | 16.0 |
| **2014** | 7.5 | 4.9 | 24.7 | 16.1 |
| **Thereafter** | 4.7 | 2.7 | 121.1 | 63.7 |
| **Total** | 74.8 | 58.7 | 255.7 | 170.6 |

We expect to fund future development costs from internally-generated funds flow, debt or equity financing through the capital markets or PET's Premium Distribution™ and Distribution Reinvestment Plan and we do not expect such costs to make development of any properties uneconomic.

The McDaniel Reports estimates that future capital costs of $255.7 million will be required over the life of PET's proved and probable reserves for the drilling, completion, equipping and tie-in of 35 conventional wells and up to 934 unconventional wells, targeting the Cretaceous Viking formation, and recompletion of up to 229 wells included in our proved and probable reserves. As our technical staff continue to analyze and evaluate the asset base and expand the facilities and pipeline infrastructure, development of the Trust's undeveloped reserves will be undertaken over the next several years. In addition to opportunities on our asset base recognized in the McDaniel Reports, many of our current assets include significant incremental exploitation and exploitation opportunities. PET has identified in its prospect inventory additional drilling recompletion and facility-related opportunities beyond those included in the McDaniel Reports. (See "**Other Oil and Gas Information – Prospect Inventory**").**Other Oil and Gas Information**

***Oil and Gas Properties***

The following is a description of our important oil and natural gas properties as at December 31, 2009. Production stated is our working and royalty interest share of production volumes and, unless otherwise stated, is average production for 2009. Reserve amounts stated include Trust Gross Reserves plus royalty interest reserves as at December 31, 2009 based on forecast costs and prices as evaluated in the McDaniel Reports. See "**Disclosure of Reserves Data**". The estimates of reserves and future net revenue for individual properties may not reflect the same confidence level as estimates of reserves and future net revenue for all properties due to the effects of aggregation. Unless otherwise specified, gross acres, net acres and well count information are as at December 31, 2009.

***Northern District***

***Athabasca***

*Calling Lake*

The Calling Lake area is located in northeast Alberta approximately 230 kilometres north of Edmonton and comprises 102,364 net acres (46.1 percent undeveloped) with an average 60.3 percent working interest in 121 gross (73.0 net) producing natural gas wells. The average daily production for 2009 from the Calling Lake area was 6.3 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 6.3 Bcf and probable reserves at 3.3 Bcf for the Calling Lake area. Current production in Calling Lake is processed through a combination of operated and third party facilities.

*Darwin*

The Darwin area is located in northeast Alberta approximately 100 kilometres northeast of Peace River and comprises 137,691 net acres (88.4 percent undeveloped) including an average 71.6 percent working interest in 19 gross (13.6 net) producing natural gas wells. The average daily production for 2009 from the Darwin area was 2.0 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 1.7 Bcf and probable reserves at 0.6 Bcf for the Darwin area. Current production in Darwin is processed through a non-operated plant where PET has a working interest.

*Marten Hills*

The Marten Hills area is located in northeast Alberta approximately 220 kilometres north of Edmonton and comprises 163,499 net acres (56.4 percent undeveloped) of which 66,123 gross (66,123 net) undeveloped acres are oil sands leases, including an average 74.6 percent working interest in 84 gross (62.2 net) producing natural gas wells. The average daily production for 2009 from the Marten Hills area was 5.8 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 9.0 Bcfe of natural gas and probable reserves at 2.3 Bcfe of natural gas. Production in the Marten Hills area is processed through a combination of third party and operated facilities.

*Mitsue*

The Mitsue area is located in northeast Alberta approximately 130 kilometres north of Edmonton and comprises 17,259 net acres (34.5 percent undeveloped) including an average 75.4 percent working interest in 22 gross (15.0 net) producing oil and natural gas wells. The average daily production for 2009 from the Mitsue area was 2.6 MMcfe/d of natural gas, oil and liquids. The McDaniel Reports evaluated our total proved reserves at 2.6 Bcfe of natural gas and probable reserves at 0.8 Bcfe of natural gas for the Mitsue area. The majority of the production in the Mitsue area is processed through a 100 percent PET owned facility with a small amount going into a third party facility.

*Panny*

The Panny area is located in northeast Alberta and comprises 165,040 net acres (81.8 percent undeveloped) of which 97,920 gross (97,920 net) undeveloped acres are oil sands leases, with an average 100.0 percent working interest in 36 gross (36.0 net) producing natural gas wells. The average daily production for 2009 from the Panny area was 4.5 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 6.5 Bcfe and probable reserves at 1.4 Bcfe for the Panny area. Current production in Panny is processed through a 100 percent PET owned gas processing facility.

*Peter Lake*

The Peter Lake area is located in northeast Alberta and comprises 33,791 net acres (42.7 percent undeveloped) with an average 94.1 percent working interest in 28 gross (26.4 net) producing natural gas wells. The average daily production for 2009 from the Peter Lake area was 4.5 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 3.3 Bcf and probable reserves at 1.4 Bcf for the Peter Lake area. Currently a majority of the production in Peter Lake is processed through two 100 percent PET owned and operated gas processing facilities, while a small amount goes through a 100 percent PET owned booster compressor and is then processed through a third party facility.

*Wabasca*

The Wabasca area is located in northeast Alberta approximately 170 kilometres north of Edmonton. The area comprises 99,142 net acres (60.7 percent undeveloped) of which 18,560 gross (18,560 net) undeveloped acres are oil sands leases, with an average 99.4 percent working interest in 80 gross (79.5 net) producing natural gas wells. The average daily production for 2009 from the Wabasca area was 11.6 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 12.3 Bcf and probable reserves at 4.7 Bcf for the Wabasca area. Current production in Wabasca is processed through a combination of 100 percent owned and operated compressor stations as well as third party facilities.

*Athabasca Other*

The other assets in the Athabasca area in northeast Alberta comprise 152,587 net acres (67.2 percent undeveloped) of which 23,040 gross (23,040 net) undeveloped acres are oil sands leases in the Duncan area, including an average 69.3 percent working interest in 64 gross (44.3 net) producing natural gas wells. The average daily production for 2009 from these assets was approximately 3.7 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 2.5 Bcf and probable reserves at 1.5 Bcf of natural gas for the Athabasca area. Production from these properties is processed through a combination of non-operated plants where PET has a working interest and third party plants.

***Northeast***

*Cold Lake/ Cold Lake Sonoma*

The Cold Lake area is in northeast Alberta approximately 250 kilometres southeast of Fort McMurray. The Cold Lake area comprises 103,765 net acres (29.2 percent undeveloped) of which 1,280 gross (512 net) undeveloped acres are oil sands leases, including an average 73.4 percent working interest in 109 (80.0 net) producing natural gas wells. The average daily production for 2009 from the Cold Lake Area was approximately 5.7 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 7.2 Bcf and probable reserves at 2.8 Bcf of natural gas for the Cold Lake area. Production from the Cold Lake area is processed through 14 booster and/or compressor stations owned by Altagas Services Inc. and four 100 percent PET owned compressor stations.

*Craigend*

The Craigend area is in northeast Alberta approximately 120 miles northeast of Edmonton. The Craigend area comprises 136,091 net acres (48.4 percent undeveloped) with an average 80.4 percent working interest in 73 (58.7net) producing natural gas wells. The average daily production for 2009 from the Craigend area was approximately 5.2 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 5.9 Bcf and probable reserves at 7.0 Bcf for the Craigend area. Production from the Craigend area is processed through a 100 percent owned and operated gas plant.

*Ells*

The Ells area is located in northeast Alberta approximately 70 kilometres northwest of Fort McMurray, and comprises 40,480 net acres (73.9 percent undeveloped) of which 15,360 gross (15,360 net) undeveloped acres are oil sands leases, as well as a 100.0 percent working interest in 24 gross (24.0 net) producing natural gas wells. The average daily production for 2009 from the Ells area was approximately 2.0 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 1.8 Bcf and probable reserves at 0.9 Bcf of natural gas for the Ells Property. The Ells area includes related facilities including a 100 percent PET owned and operated gas plant and a booster compressor station.

*Kettle/ Chard /Quigley*

The Chard/Kettle/Quigley area is in northeast Alberta approximately 80 kilometres south of Fort McMurray. The area comprises 132,648 net acres (52.0 percent undeveloped) including an average 93.7 percent working interest in 55 (51.5 net) producing natural gas wells. The average daily production for 2009 from the Chard area, including Kettle and

Quigley, was approximately 3.7 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 3.6 Bcf and probable reserves at 2.0 Bcf of natural gas for the Chard/Kettle/Quigley area. In addition, we have 0.1 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. A majority of the production from the area is processed through a 100 percent PET owned gas plant at Kettle River. Two booster compressors reduce gathering system pressures to optimize production.

*Legend*

The Legend area, including East Legend, is approximately 110 kilometres northwest of Fort McMurray. The area comprises 204,947 net acres (61.5 percent undeveloped) of which 7,680 gross (7,680 net) undeveloped acres are oil sands leases, including an average 90.1 percent working interest in 90 (81.1 net) producing natural gas wells. The average daily production for 2009 from the Legend area was approximately 8.6 MMcf/d of natural gas. The McDaniel Reports evaluated our Probable reserves at 20.4 Bcf of natural gas for the Legend area which are shut-in as a result of the gas over bitumen issue in this area. We have a 78.8 percent interest in an operated gas plant and nine field booster compressors with working interests ranging from 86.9 percent to 100 percent, which are used to process the natural gas from this area.

*Leismer, Corner*

The Corner/Leismer area is in northeast Alberta approximately 90 kilometres southwest of Fort McMurray. The area comprises 315,035 net acres (54.2 percent undeveloped) including a 95.1 percent working interest in 89 gross (84.7 net) producing natural gas wells. The average daily production for 2009 from the Corner/Leismer area was approximately 5.7 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 5.9 Bcf and probable reserves at 2.9 Bcf of natural gas for the Corner/Leismer area. In addition, we have 17.6 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the Corner/Leismer area is processed through five 100 percent PET owned field booster compressors and one gas plant 32.5 percent owned by PET.

*Liege*

The Liege area is in northeast Alberta approximately 120 kilometres west of Fort McMurray. The area comprises 262,386 net acres (72.1 percent undeveloped) of which 75,520 gross (75,520 net) undeveloped acres are oil sands leases, including an average 91.2 percent working interest in 57 gross (52.0 net) producing natural gas wells. The average daily production for 2009 from the Liege Area, including South, North and East Liege, was approximately 4.1 MMcf/d of natural gas. The McDaniel Reports evaluated PET's total proved reserves at 7.2 Bcf and probable reserves at 6.8 Bcf of natural gas for the Liege area. In addition, we have 0.6 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the Liege area is processed through the South Liege gas plant owned 80.5 percent by PET. The North Liege production flows through a 100 percent PET owned booster compressor to a third party plant for processing.

*Saleski*

The Saleski area is in northeast Alberta approximately 110 kilometres west of Fort McMurray. The area comprises 125,997 net acres (73.1 percent undeveloped) of which 1,280 gross (256 net) undeveloped acres are oil sands leases, including an average 79.1 percent working interest in 40 gross (31.6 net) producing natural gas wells. The average daily production for 2009 from the Saleski area was approximately 4.7 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 12.6 Bcf and probable reserves at 4.7 Bcf of natural gas for the Saleski area. Production at Saleski is processed through one gas plant owned 58.6 percent and operated by PET.

*Teepee Creek*

The Teepee Creek area is in northeast Alberta approximately 175 kilometres west of Fort McMurray. The area comprises 20,720 net acres (23.2 percent undeveloped) including an average 90.0 percent working interest in 20 gross (18.0 net) producing natural gas wells. The average daily production for 2009 from the Teepee Creek area was 1.1 MMcf/d. The McDaniel Reports evaluated our total proved reserves at 0.7 Bcf and probable reserves at 0.2 Bcf of natural gas for the

Teepee Creek area. Production from the Teepee Creek area is processed through a 100 percent PET owned and operated gas plant.

*Thornbury*

The Thornbury area is in northeast Alberta approximately 75 kilometres southwest of Fort McMurray. The area comprises 58,020 net acres (41.8 percent undeveloped) including an average 79.1 percent working interest in 55 (43.5 net) producing natural gas wells. The average daily production for 2009 from the Thornbury area was approximately 4.6 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 6.0 Bcf and probable reserves at 1.9 Bcf of natural gas for the Thornbury area. In addition, we have 0.5 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the Thornbury area is processed through four gas plants and a field booster compressor owned by a third party.

*Woodenhouse*

The Woodenhouse area is located in northeast Alberta approximately 140 kilometres southwest of Fort McMurray and 300 kilometres north of Edmonton and comprises 130,374 net acres (51.8 percent undeveloped) of which 12,800 gross (12,800 net) undeveloped acres are oil sands leases, with an average 100.0 percent working interest in 68 gross (68.0 net) producing natural gas wells. The average daily production for 2009 from the Woodenhouse area was 6.2 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 8.1 Bcf and probable reserves at 2.6 Bcf for the Woodenhouse area. Current production in Woodenhouse is processed through a 100 percent PET owned and operated gas plant.

*Northeast Other*

The other assets in the Northeast area in Alberta comprise 203,125 net acres (56.7 percent undeveloped); including an average 58.3 percent working interest in 110 gross (64.2 net) producing natural gas wells. The average daily production for 2009 from these assets was approximately 6.0 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 6.3 Bcf and probable reserves at 2.1Bcf of natural gas for the Athabasca area. In addition, we have 6.3 Bcf of probably reserves shut-in as a result of the gas over bitumen issue in this area. Production from these properties is processed through a combination of non-operated plants where PET has a working interest and third party plants.

***Southern District***

***Birchwavy East***

*Duvernay*

The Duvernay area comprises 188,044 net acres (33.0 percent undeveloped) including an average 85.5 percent working interest in 165 gross (141.1 net) producing wells. The average daily production for 2009 from the Duvernay area was 15.2 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 22.3 Bcf and probable reserves at 39.7 Bcf. Production in Duvernay is processed through a combination of an owned and operated plant, thru non-operated plants where PET has a working interest, and third party plants.

*Mannville*

The Manville area comprises 128,527 net acres (22.7 percent undeveloped) including an average 95.6 percent working interest in 113 gross (107.7 net) producing wells. The average daily production for 2009 from the Manville area was 8.5 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 18.7 Bcfe and probable reserves at 16.4 Bcfe. Production in Manville is processed through two plants owned and operated by PET.

*Viking Kinsella*

The Viking Kinsella area comprises 97,558 net acres (51.8 percent undeveloped) including an average 72.1 percent working interest in 165 gross (141.1 net) producing wells. The average daily production for 2009 from the Viking Kinsella area was 4.2 MMcfe/d of natural gas, oil and liquids. The McDaniel Reports evaluated our total proved reserves at 10.7 Bcfe and probable reserves at 4.1 Bcfe. Production in Viking Kinsella is processed through a combination of an owned and operated plant, a non-operated plant where PET has a working interest, and third party plants.

***Birchwavy West***

*Bruce*

The Bruce area comprises 212,343 net acres (28.1 percent undeveloped) including an average 78.6 percent working interest in 187 (146.7 net) producing wells. The average daily production for 2009 from the Bruce area was 7.4 MMcfe/d of natural gas, oil and liquids. The McDaniel Reports evaluated our total proved reserves at 22.4 Bcfe and probable reserves at 31.7 Bcf. Production in Bruce is processed through one 91.5 percent owned and operated PET plant and third party plants.

*Killam*

The Killam area comprises 61,738 net acres (61.6 percent undeveloped) including an average 68.2 percent working interest in 43 gross (30.5 net) producing wells. The average daily production for 2009 from the Killam area was 2.6 MMcf/d of natural gas. The majority of the assets in this area were acquired through the Birchwavy Acquisition. The McDaniel Reports evaluated our total proved reserves at 3.2 Bcfe and probable reserves at 1.3 Bcf. Production in Killam is processed through a small 100 percent owned and operated plant and other third party plants.

*Warwick*

The Warwick area comprises 155,830 net acres (56.7 percent undeveloped) including an average 86.0 percent working interest in 111 gross (92.0 net) producing wells. The average daily production for 2009 from the Warwick area was 6.3 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 14.6 Bcf and probable reserves and probable reserves at 17.2 Bcf. Production in Warwick is processed through a combination of an owned and operated plant and third party plants.

***Other Southern***

Other non-core assets in the Southern area comprise 15,267 net acres (75.7 percent undeveloped) including an average 43.3 percent working interest in 197 gross (83.4 net) producing natural gas wells. The average daily production for 2009 from the Other Southern area was 1.0 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 1.0 Bcfe and probable reserves at 0.5 Bcfe. Production is processed through a combination of 100 percent owned facilities and several third party facilities.

***West Central***

*Carrot Creek*

The Carrot Creek area comprises 20,355 net acres (35.0 percent undeveloped) including an average 60.4 percent working interest in 40 gross (23.4 net) producing wells. The average daily production from July 1, 2009 to December 3, 2009 for the Carrot Creek area was 4.1 MMcfe/d of natural gas, oil and liquids. The McDaniel Reports evaluated our total proved reserves at 19.9 Bcfe and probable reserves at 8.9 Bcfe. Production in Carrot Creek is processed through a non-operated plant and other third party facilities where PET has working interest.

*Cochrane*

The Cochrane area comprises 13,938 net acres (89.0 percent undeveloped) including an average 60.0 percent working interest in 2 gross (1.2 net) producing wells. The average daily production from July 1, 2009 to December 3, 2009 for the Cochrane area was 0.2 MMcfe/d of natural gas, oil and liquids. The McDaniel Reports evaluated our total proved reserves at 1.6 Bcfe and probable reserves at 1.3 Bcfe. Production in Cochrane is processed through an PET owned and operated plant.

*Grande Prairie*

The Grande Prairie area comprises 15,448 net acres (65.5 percent undeveloped) including an average 72.1 percent working interest in 7 gross (6.2 net) producing wells. The average daily production from July 1, 2009 to December 3, 2009 for the Grande Prairie area was 1.8 MMcfe/d of natural gas, oil and liquids. The McDaniel Reports evaluated our total proved reserves at 6.9 Bcfe and probable reserves at 2.7 Bcfe. Production in Grande Prairie is processed through an owned and operated plant, through non-operated plants where PET has a working interest and third party plants.

*Pembina*

The Pembina area comprises 27,247net acres (62.0 percent undeveloped) including an average 62.9 percent working interest in 20 gross (12.2 net) producing wells. The average daily production from July 1, 2009 to December 3, 2009 for the Pembina area was 0.7 MMcfe/d of natural gas, oil and liquids. The McDaniel Reports evaluated our total proved reserves at 6.7 Bcfe and probable reserves at 4.3 Bcfe. Production in Pembina is processed through owned and operated plants, as well as third party plants.

*West Central Other*

Other non-core assets in the West Central area comprise 94,549 net acres (88.4 percent undeveloped) including an average 77.8 percent working interest in 17 gross (12.6 net) producing natural gas wells. The average daily production for 2009 from the West Central Other area was 0.7 MMcfe/d of natural gas and heavy oil. The McDaniel Reports evaluated our total proved reserves at 2.2 Bcfe and probable reserves at 1.4 Bcfe. Production from these areas is processed through a combination of 100 percent owned and operated facilities and several third party plants.

***Severo Energy Corp.***

*Big Bend/Radway*

In 2006 PET completed an internal restructuring in order to facilitate the development of certain assets south of its Athabasca core area that were primarily lower working interest and non-operated. Assets in the Big Bend and Radway areas producing approximately 1.4 MMcf/d were transferred to a private company, Severo Energy Corp. ("Severo"), which is 93 percent indirectly owned by PET. The Big Bend and Radway areas are located in northeast Alberta approximately 100 kilometres north of Edmonton and comprise 127,327 net acres (46.8 percent undeveloped) with an average 53.9 percent working interest in 105 (56.7 net) producing natural gas wells. Including certain assets acquired in the Craigend/Radway/Stry Acquisition, the average daily production for 2009 from the Big Bend/Radway area was 5.5 MMcf/d of natural gas. The McDaniel Reports evaluated our total proved reserves at 4.7 Bcf and probable reserves at 2.7 Bcf for the Big Bend area. Current production in Big Bend/Radway is processed through a combination of operated and third party facilities.

### *Oil and Gas Wells*

The following table sets forth the number and status of wells in which we had a working interest as at December 31, 2009.

| Property | Producing Gas Wells | | Producing Oil Wells | | Non-Producing Gas Wells(3)(4) | | Non-Producing Oil Wells(3)(4) | |
|---|---|---|---|---|---|---|---|---|
| | Gross(1) | Net(2) | Gross(1) | Net(2) | Gross(1) | Net(2) | Gross(1) | Net(2) |
| **Northern District** | | | | | | | | |
| **Athabasca** | | | | | | | | |
| Calling Lake | 121 | 73.0 | - | - | 64 | 27.4 | - | - |
| Darwin | 19 | 13.6 | - | - | 21 | 15.8 | - | - |
| Marten Hills | 84 | 62.2 | 2 | 2.0 | 74 | 61.4 | - | - |
| Mitsue | 22 | 15.0 | 9 | 8.4 | 7 | 3.5 | 3 | 0.8 |
| Panny | 36 | 36.0 | 1 | 1.0 | 9 | 9.0 | 1 | 1.0 |
| Peter Lake | 28 | 26.4 | - | - | 11 | 10.2 | 7 | 7.0 |
| Wabasca | 80 | 79.5 | - | - | 25 | 20.7 | 8 | 7.5 |
| Athabasca Other | 64 | 44.3 | - | - | 55 | 42.2 | - | - |
| Athabasca subtotal | 454 | 349.9 | 12 | 11.4 | 266 | 190.3 | 19 | 16.3 |
| **Northeast Alberta** | | | | | | | | |
| Cold Lake/ Cold Lake Sonoma | 109 | 80.0 | - | - | 47 | 38.8 | 2 | 1.3 |
| Craigend | 73 | 58.7 | - | - | 53 | 41.9 | 10 | 10.0 |
| Ells | 24 | 24.0 | - | - | 6 | 5.0 | - | - |
| Kettle, Chard, Quigley | 55 | 51.5 | - | - | 61 | 59.2 | - | - |
| Legend | 90 | 81.1 | - | - | 80 | 53.1 | - | - |
| Leismer, Corner | 89 | 84.7 | - | - | 151 | 145.5 | - | - |
| Liege (South, North, and East) | 57 | 52.0 | - | - | 63 | 59.9 | 1 | 1.0 |
| Saleski | 40 | 31.6 | - | - | 25 | 23.1 | - | - |
| Tepee Creek | 20 | 18.0 | - | - | 8 | 6.8 | - | - |
| Thornbury | 55 | 43.5 | - | - | 26 | 18.4 | - | - |
| Woodenhouse | 68 | 68.0 | - | - | 39 | 39.0 | - | - |
| Northeast Other | 110 | 64.2 | - | - | 138 | 76.9 | - | - |
| Northeast subtotal | 681 | 657.3 | - | - | 697 | 567.5 | 13 | 12.3 |
| **Southern District** | | | | | | | | |
| **Birchwavy East** | | | | | | | | |
| Duvernay | 112 | 83.7 | 84 | 57.6 | 50 | 36.5 | 30 | 20.4 |
| Mannville | 113 | 107.7 | 6 | 6.0 | 56 | 51.3 | 3 | 3.0 |
| Viking Kinsella | 165 | 141.1 | - | - | 92 | 79.9 | - | - |
| Birchwavy East subtotal | 390 | 332.5 | 90 | 63.6 | 198 | 167.8 | 33 | 23.4 |
| **Birchwavy West** | | | | | | | | |
| Bruce | 187 | 146.8 | 1 | 1.0 | 80 | 57.3 | - | - |
| Killam | 43 | 30.5 | 19 | 11.8 | 33 | 25.8 | 7 | 2.1 |
| Warwick | 111 | 92.0 | 25 | 25.0 | 59 | 49.7 | 2 | 1.7 |
| Birchwavy West subtotal | 341 | 269.3 | 45 | 37.8 | 172 | 132.7 | 9 | 3.8 |
| **Other Southern** | 197 | 83.4 | 5 | 4.1 | 39 | 24.4 | 11 | 10.5 |
| **West Central District** | | | | | | | | |
| Carrot Creek | 40 | 23.4 | 8 | 5.6 | 4 | 1.5 | 2 | 0.4 |
| Cochrane | 2 | 1.2 | - | - | - | - | - | - |
| Grande Prairie | 7 | 6.2 | 5 | 2.5 | 1 | 1.0 | 2 | 1.3 |
| Pembina | 20 | 12.2 | 3 | 2.3 | - | - | - | - |
| West Central Other | 17 | 12.6 | 3 | 3.0 | 5 | 4.7 | 3 | 2.1 |

| | | | | | | | | |
|---|---|---|---|---|---|---|---|---|
| West Central subtotal | 86 | 55.5 | 19 | 13.4 | 10 | 7.2 | 7 | 3.8 |
| **Severo Energy Corp.** | | | | | | | | |
| Big Bend/Radway | 129 | 69.5 | - | - | 293 | 180.5 | - | - |
| **TOTAL** | 2,278 | 1,817.4 | 171 | 130.2 | 1,675 | 1,270.4 | 92 | 70.0 |

"**Gross**" refers to the number of wells, respectively, in which a working interest is held by PET. In addition PET held royalty interests 133 wells at December 31, 2009.
"**Net**" refers to the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest therein.
"**Non-Producing**" refers to wells which are not currently producing either due to lack of facilities, markets or regulatory approval. This includes 254 gross (190.7 net) wells shut-in as a result of gas over bitumen regulatory rulings.
Allowance for the abandonment costs associated with the well bores was made in the McDaniel Reports. There are 90 wells that are classified as service wells not included in the gross/net well count.
**Athabasca Other** includes Caribou, Duncan, Edwand, Figure Lake Hercules, Mitsue, Portage, Ryan, Steele, and Stry.
**Northeast Other** includes Birch Tar, Bohn Lake, Clyde, Hospital Creek, Jean Lake, Pony, and Winefred.
**Other Southern** includes Cabin Creek, Highvale, Saskatchewan, Sedalia, Craigmyle, Medicine Hat, Lacadena, Baldwinton, Kirkpatrick, Unity and Eyremore.
**West Central Other** includes Cabin Creek, Edson, Elmworth, Garrington, Gold Creek/ Karr, Peace River Arch, and Willesden Green.

### *Acreage Information*

The following table sets out our developed and undeveloped land holdings as at December 31, 2009. We do not have any material work commitments on any of our properties.

| | **Developed Acres** | | **Undeveloped Acres** | |
|---|---|---|---|---|
| **Property** | **Gross(1)** | **Net(2)** | **Gross(1)** | **Net(2)** |
| **Northern District** | | | | |
| **Athabasca** | | | | |
| Calling Lake | 109,600 | 55,211 | 73,280 | 47,153 |
| Darwin | 24,160 | 16,010 | 126,880 | 121,681 |
| Marten Hills | 96,402 | 71,225 | 96,324 | 92,275 |
| Marten Hills Oil Sands Leases | - | - | 66,123 | 66,123 |
| Mitsue | 18,082 | 11,303 | 8,640 | 5,956 |
| Panny | 30,944 | 30,080 | 135,744 | 134,960 |
| Panny Oil Sands Leases | - | - | 97,920 | 97,920 |
| Peter Lake | 23,235 | 19,372 | 16,738 | 14,419 |
| Peter Lake Oil Sands Leases | - | - | 640 | 640 |
| Wabasca | 41,634 | 38,994 | 65,847 | 60,147 |
| Wabasca Oil Sands Leases | 640 | 320 | 18,560 | 18,560 |
| Athabasca Other | 110,937 | 50,075 | 117,190 | 102,512 |
| Athabasca Other Oil Sands Leases | - | - | 23,040 | 23,040 |
| Athabasca subtotal | 454,994 | 292,269 | 640,642 | 579,104 |
| **Northeast Alberta** | | | | |
| Cold Lake/ Cold Lake Sonoma | 100,490 | 73,462 | 41,421 | 30,304 |
| Cold Lake/Cold Lake Sonoma Oil Sands Leases | - | - | 1,280 | 512 |
| Craigend | 87,825 | 70,227 | 80,855 | 65,864 |
| Ells | 11,520 | 10,560 | 32,640 | 29,920 |
| Ells Oil Sands Leases | - | - | 15,360 | 15,360 |
| Kettle, Chard, Quigley | 68,480 | 63,660 | 73,600 | 68,988 |
| Legend | 103,040 | 78,809 | 157,440 | 126,138 |
| Legend Oil Sands Leases | - | - | 7,680 | 7,680 |
| Leismer, Corner | 150,010 | 144,405 | 184,070 | 170,630 |
| Liege (South, North, and East) | 84,640 | 73,159 | 218,080 | 189,227 |
| Liege (South, North, and East) Oil Sands Leases | - | - | 75,520 | 75,520 |
| Saleski | 39,200 | 33,950 | 109,600 | 92,047 |

| Property | Developed Acres Gross[1] | Developed Acres Net[2] | Undeveloped Acres Gross[1] | Undeveloped Acres Net[2] |
|---|---|---|---|---|
| Saleski Oil Sands Leases | - | - | 1,280 | 256 |
| Tepee Creek | 18,560 | 15,920 | 7,040 | 4,800 |
| Thornbury | 45,440 | 33,764 | 27,520 | 24,256 |
| Woodenhouse | 63,015 | 62,829 | 67,545 | 67,545 |
| Woodenhouse Oil Sands Leases | - | - | 12,800 | 12,800 |
| Northeast Other | 166,444 | 87,859 | 236,887 | 115,265 |
| Northeast Other Oil Sands Leases | - | - | 3,840 | 3,840 |
| Northeast subtotal | 938,664 | 748,604 | 1,236,698 | 984,985 |
| | | | | |
| **Southern District** | | | | |
| **Birchwavy East** | | | | |
| Duvernay | 167,682 | 125,922 | 68,652 | 62,123 |
| Mannville | 112,467 | 99,399 | 30,967 | 29,128 |
| Viking Kinsella | 111,451 | 47,027 | 62,199 | 50,532 |
| Birchwavy East subtotal | 391,600 | 272,347 | 161,818 | 141,782 |
| | | | | |
| **Birchwavy West** | | | | |
| Bruce | 221,628 | 152,768 | 63,360 | 59,575 |
| Killam | 50,546 | 23,703 | 54,137 | 38,035 |
| Warwick | 142,553 | 67,439 | 97,060 | 88,391 |
| Birchwavy West subtotal | 414,727 | 243,910 | 214,557 | 186,002 |
| | | | | |
| **Other Southern** | 29,002 | 3,703 | 14,947 | 11,564 |
| | | | | |
| **West Central** | | | | |
| Carrot Creek | 24,206 | 13,223 | 10,880 | 7,132 |
| Cochrane | 2,560 | 1,536 | 16,665 | 12,402 |
| Grande Prairie | 6,880 | 5,336 | 13,280 | 10,112 |
| Pembina | 17,600 | 10,342 | 21,760 | 16,906 |
| West Central Other | 23,040 | 10,965 | 96,475 | 83,584 |
| West Central Other Oil Sands Leases | - | - | 3,840 | 3,840 |
| West Central subtotal | 74,286 | 41,402 | 159,060 | 130,135 |
| | | | | |
| **Severo Energy Corp.** | | | | |
| Big Bend/Radway | 156,258 | 67,742 | 86,473 | 59,584 |
| | | | | |
| **TOTAL** | **2,459,532** | **1,669,977** | **2,514,195** | **2,093,155** |

(1) "Gross" means the total number of acres in which we have an interest in respect of our current assets.
"Net" means the aggregate of the numbers obtained by multiplying each gross acre by the actual percentage interest therein.
During 2010, 206,214.6 net acres are set to expire. We intend to assess such expiring lands and, where appropriate, seek continuation through mapping, development activity or, in the case of higher risk areas, farm outs, where third parties provide exploration funding in exchange for an earned working interest.
"Undeveloped Acres" refers to land where there are not any existing wells within the rights associated with those lands
**Athabasca Other** includes Caribou, Duncan, Edwand, Figure Lake Hercules, Portage, Ryan, Steele, and Stry.
**Northeast Other** includes Birch Tar, Bohn Lake, Clyde, Hospital Creek, Jean Lake, Pony, and Winefred.
**Other Southern** includes Cabin Creek, Highvale, Saskatchewan, Sedalia, Craigmyle, Medicine Hat, Lacadena, Baldwinton, Kirkpatrick, Unity and Eyremore.
**West Central Other** includes Cabin Creek, Edson, Elmworth, Garrington, Gold Creek/ Karr, Peace River Arch, and Willesden Green.

### *Production Estimates*

The following table sets out the volume of our production estimated by McDaniel on a proved and probable basis for the year ended December 31, 2010, which is reflected in the estimate of future net revenue disclosed in the tables contained under **STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION IN ACCORDANCE WITH FORM 51-101F1.**

| **2010 McDaniel Forecast Production** | **Natural Gas (MMcfe/d)** | **Crude Oil (Mbbl/d)** | **Natural Gas Liquids (Mbbl/d)** |
|---|---|---|---|
| Proved | 136.9 | 0.6 | 0.5 |
| Probable | 9.0 | 0.0 | 0.0 |
| Total Proved and Probable | **147.9** | **0.6** | **0.5** |

### *Production History*

The following tables summarize certain information in respect of production, product prices received, royalties paid, operating expenses and resulting netback for the periods indicated below:

| | **2009 Quarter Ended** | | | |
|---|---|---|---|---|
| | **Dec 31** | **Sept 30** | **June 30** | **Mar 31** |
| Average Daily Production Volume | | | | |
| Natural Gas (MMcfe/d) | 145.9 | 152.4 | 165.5 | 167.1 |
| Average Realized Price ($/Mcfe) | 5.87 | 7.50 | 9.10 | 6.46 |
| Royalties Paid ($/Mcfe) | (0.22) | (0.20) | (0.18) | (0.59) |
| Operating Costs ($/Mcfe) | (1.41) | (1.99) | (1.67) | (2.20) |
| Transportation Costs ($/Mcfe) | (0.21) | (0.16) | (0.22) | (0.22) |
| Netback ($/Mcfe) | 4.03 | 5.15 | 7.03 | 3.45 |

The following table indicates our average daily production from each of PET's core areas for the year ended December 31, 2009:

| **Property** | **Production** (MMcfe/d) |
|---|---|
| **Northern Region** | |
| **Athabasca** | |
| Calling Lake | 6.3 |
| Darwin | 2.0 |
| Marten Hills | 5.8 |
| Mistahae | 0.8 |
| Mitsue | 2.6 |
| Panny | 4.5 |
| Peter Lake | 4.5 |
| Wabasca | 11.6 |
| Athabasca Other | 3.7 |
| Athabasca subtotal | 41.8 |
| | |
| **Northeast Alberta** | |
| Cold Lake/ Cold Lake Sonoma | 5.7 |
| Craigend | 5.2 |
| Ells | 2.0 |

| | |
|---|---|
| Kettle, Chard, Quigley | 3.7 |
| Legend | 8.6 |
| Leismer, Corner | 5.7 |
| Liege (South, North, and East) | 4.1 |
| Saleski | 4.7 |
| Tepee Creek | 1.1 |
| Thornbury | 4.6 |
| Woodenhouse | 6.2 |
| Northeast Other | 6.0 |
| Northeast subtotal | 57.5 |
| **Southern Region** | |
| **Birchwavy East** | |
| Duvernay | 15.2 |
| Mannville | 8.5 |
| Viking Kinsella | 4.2 |
| Birchwavy East subtotal | 28.0 |
| **Birchwavy West** | |
| Bruce | 7.4 |
| Killam | 2.6 |
| Warwick | 6.3 |
| Birchwavy West subtotal | 16.4 |
| **Other Southern** | 1.0 |
| **West Central Region** | |
| Carrot Creek | 4.1 |
| Cochrane | 0.2 |
| Grande Prairie | 1.8 |
| Pembina | 0.7 |
| West Central Other | 0.7 |
| West Central subtotal | 7.5 |
| **Severo Energy Corp.** | |
| Big Bend/Radway | 5.5 |
| **TOTAL** | **157.7** |

### *Prospect Inventory*

The Trust has identified numerous exploitation, development and low exposure exploration opportunities which are not recorded in the McDaniel Reports as these opportunities do not meet the criteria to be booked as proved or probable reserves under NI 51-101. These prospects are at various degrees of technical refinement but are generally believed to be relatively low risk and will be pursued during 2010 and beyond through drilling, completion and tie-in activities or evaluated further with additional seismic. These will be pursued as they are technically refined and as economic factors such as commodity prices, proximity to infrastructure, operating costs, and gas production rates permit. The spending of additional capital beyond the estimates contained in the McDaniel Reports will increase value to Unitholders through the addition of production and reserves from new pools or acceleration of production in existing pools to decrease gas production rate declines with a corresponding increase in recoverable reserves, and a reduction in the number of years fixed costs are incurred. Facility optimization projects target production and reserves additions through improved recovery and by reducing operating costs to extend the economic life of producing assets with a corresponding increase in recoverable reserves.

***Conventional Shallow Gas Opportunities***

While the McDaniel Reports include costs and reserves for the drilling of only 35 conventional natural gas wells, we are pursuing the drilling of over 99 gross wells as part of our 2010 capital expenditure budget. Further the Trust's evaluation of its prospect inventory has identified more than 750 additional conventional drilling opportunities on PET lands targeting cretaceous Mannville and Devonian shallow gas including pool extensions, downspacing for new pools on developed lands and low exposure exploration on undeveloped lands. Additional drilling prospects are at varying levels of technical analysis and economic evaluation. In addition, potential exists for incremental gas production through recompletion of uphole zones in existing wells and optimization of facilities. Over 1,100 workovers and secondary zone completions have been identified that are not identified in the McDaniel Reports. The Trust's inventory of conventional drilling opportunities is continually replenished with the direction of a portion of the Trust's annual capital expenditure budget to Crown and freehold land purchases.

***Unconventional Viking and Colorado Shale***

We have developed an inventory of unconventional Viking formation tight gas opportunities including 1,067 drilling and recompletion targets included in the McDaniel Reports well counts. We have also identified in excess of 1,200 future drilling locations targeting the Viking formation and Colorado shale that were not included in the McDaniel Reports. These will be pursued in orderly development with recompletions following the depletion of the underlying Mannville reservoirs and multi-well drilling programs initiated as economic and technical conditions dictate.

***Bitumen Land Bank***

The Trust has positioned itself with 327,883 gross (326,091 net) undeveloped oil sands leases throughout many of its shallow gas operating areas in northeast Alberta including Duncan, Clyde, Cold Lake, Ells, Marten Hills, Legend, Liege, Panny, Peace River Arch, Saleski, Wabasca/Hoole, and Woodenhouse. The bitumen resource potential on these leases will likely be developed over the long term using a variety of recovery techniques ranging from cold production to in-situ techniques such as SAGD technology.

***West Central Alberta Exploration***

The Trust has accumulated 159,060 gross (130,135 net) acres of undeveloped land in West Central Alberta. The primary target is a high impact resource style tight gas play. Exploration activities on these lands are planned in the next several years. If economically and technically successful the lands will warrant significant capital for future development activities. The Trust has increased its focus on growth opportunities in 2010, with plans in place to exploit several of its opportunities in the Montney formation at Elmworth, the Cardium formation at Carrot Creek and Pembina. In the Elmworth area, PET and its partner are preparing to drill three horizontal (1.5 net) Montney gas wells, with the first well expected to spud in July 2010.

***Capital Expenditures***

The following tables summarize capital expenditures related to our activities for the year ended December 31, 2009:

| ($millions) | |
|---|---|
| Exploration and development expenditures | $64.3 |
| Crown and freehold land purchases | $3.9 |
| Acquisitions | 17.6 |
| Profound acquisition – cash consideration | 27.5 |
| Profound acquisition – Trust unit consideration | 32.2 |
| Profound acquisition – assumption of net debt | 53.3 |
| Dispositions | (26.5) |
| Other | 0.6 |
| **Total** | **$ 172.7** |

Exploration and development expenditures for 2009 include approximately $6.4 million in exploration costs which have been expensed directly on the Trust's statement of earnings. Exploration costs include seismic expenditures and dry hole costs and are considered by PET to be more closely related to investing activities than operating activities; as a result they are included with capital expenditures.

### *Exploration and Development Activities*

The following table sets forth the gross and net exploratory and development wells in which we participated during the year ended December 31, 2009:

| | Gross | Net |
|---|---|---|
| **Exploratory Wells** | | |
| Light and Medium Oil | - | - |
| Natural Gas | 19 | 13.5 |
| Service | - | - |
| Dry | - | - |
| **Total** | 19 | 13.5 |
| Success Rate (%) | 100 | 100 |
| **Development Wells** | | |
| Light and Medium Oil | 2 | 2.0 |
| Natural Gas | 31 | 26.7 |
| Service | - | - |
| Dry | - | - |
| **Total** | 33 | 28.7 |
| Success Rate (%) | 100 | 100 |

### *Additional Information Concerning Abandonment and Reclamation Costs*

PET engages Prevent Technologies Ltd. ("Prevent"), an independent evaluator, to estimate the Trust's total future asset retirement obligation, based on net ownership interest in all wells and facilities, including wells with no reserves attributed including costs to abandon the wells, facilities and pipelines and reclaim the sites and the estimating timing of the costs to be incurred in future periods. Pursuant to this evaluation, the estimated undiscounted total value of PET's future asset retirement obligations is $343 million as at December 31, 2009. As at December 31, 2009, the undiscounted net salvage value of the Trust's gas plants, compressors and facilities was estimated at $127 million. The McDaniel Report includes an undiscounted amount of $134 million with respect to expected future well abandonment costs related specifically to proved and probable reserves and such amount is included in the values captioned "Proved and Probable" in the summary tables of Net Present Value of Future Revenue (See **"Disclosure of Reserves Data"**). Of the total future well abandonment costs included in the McDaniel report an undiscounted amount of $104 million relates to PET's developed reserves. The following table presents the estimated future asset retirement obligations and estimated net salvage values at various discount rates:

| ($MM, net to PET) | Undiscounted | 5% | 8% | Discounted at 10% |
|---|---|---|---|---|
| Well abandonment costs for developed reserves included in McDaniel Report | 104 | 72 | 59 | 53 |
| Well abandonment costs for undeveloped reserves included in McDaniel Report | 30 | 15 | 10 | 8 |
| Well abandonment costs for total proved and probable reserves included in McDaniel Report | 134 | 87 | 70 | 61 |
| Estimate of other abandonment and reclamation costs not included in McDaniel Report | 209 | 136 | 108 | 94 |
| **Total estimated future abandonment and reclamation costs** | **343** | **223** | **178** | **155** |
| Salvage value | (127) | (82) | (66) | (58) |
| Abandonment and reclamation costs, net of salvage | **216** | **141** | **112** | **97** |
| Well abandonment costs for developed reserves included in McDaniel Report(1) | (104) | (72) | (59) | (53) |
| Estimate of additional future abandonment and reclamation costs, net of salvage (1) | 112 | 69 | 53 | 44 |

Future abandonment and reclamation costs not included in the McDaniel Report, net of salvage value.

### *Marketing and Transportation*

We proactively manage our gas portfolio in order to maximize the price we obtain for our production. Our internal team of gas marketing professionals is responsible for hands-on management of our physical gas sales and hedging, including transportation and storage arrangements. Continuous market surveillance and analysis leads us to employ various hedging tools and pricing arrangements to, among other things:

- Protect the level of monthly distributions;
- Enhance or protect the economics of an acquisition by capturing pricing either at the same level or higher than the original evaluation; and
- Capitalize on short-term anomalies in the market.

Aside from the physical forward sales contracts at AECO fixed prices outlined below, we currently have no material future contracts to buy, sell, exchange or transport natural gas from our assets. According to January estimates, we currently sell approximately 90 percent of our gas production at AECO-based market prices. The remaining 10 percent is directed to natural gas aggregator pools.

For a complete list of PET's outstanding financial instruments as at December 31, 2009, please see note 11 to the annual consolidated financial statements as at and for the year ended December 31, 2009. PET continued to supplement its risk management program after the end of the year. Financial and physical natural gas forward sales positions (net of related financial and physical fixed-price natural gas purchase contracts) at March 8, 2010 are as follows.

| Type of Contract | Volumes at AECO(2) (GJ/d) | % of 2010 Budgeted Volume(4) | Price (1) ($/GJ) | Futures Market(3) ($/GJ) | Term |
|---|---|---|---|---|---|
| Financial | 90,000 | 46 | 4.55 | 4.31 | April – October 2010 |
| Financial | 85,000 | | 7.83 | | November 2010 – March 2011 |
| Physical | 10,000 | | 7.75 | | November 2010 – March 2011 |
| Period Total | 95,000 | 49 | 7.82 | 5.13 | November 2010 – March 2011 |
| Financial | 30,000 | 15 | 6.28 | 5.01 | April – October 2011 |
| Financial | 89,679 | 46 | 6.78 | 6.01 | January – March 2013 |

Average price calculated using weighted average price for sell contracts.
All transactions are at AECO unless identified specifically as a NYMEX transaction.
Futures market reflects AECO/NYMEX forward market prices as at March 8, 2010.

Calculated using 194,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes and voluntary production shut-ins.

PET has also entered into a financial collar arrangement. The collar consists of 1,000 GJ/d with a floor of $5.00/GJ and a ceiling of $7.55 per GJ for the term January 2010 to March 2010.

As part of PET's risk management strategy, the Trust has also sold forward financial call options to counterparties to purchase natural gas from PET at strike prices in excess of current forward prices. Option premiums of $10.7 million have been received and included in funds flows in respect of these transactions, of which $3.4 million relates to 2008, $5.7 million relates to 2009 and $1.6 million relates to the first quarter of 2010. Call option contracts outstanding as of March 8, 2010 are as follows.

| Type of Contract | Volumes at AECO (GJ/d) | % of 2010 Budgeted Production(2) | Strike Price(1) ($/GJ) | Futures Market(3) ($/GJ) | Term |
|---|---|---|---|---|---|
| Sold call | 6,000 | 3 | 8.34 | 5.08 | January – March 2010 |
| Sold call | 20,000 | 10 | 7.25 | 4.64 | January – December 2010 |
| Sold call | 15,000 | 8 | 7.08 | 4.31 | April – October 2010 |
| Sold call | 32,500 | 17 | 8.00 | 5.13 | November 2010 – March 2011 |
| Sold call | 25,000 | 13 | 6.00 | 5.01 | April – October 2011 |

Weighted average prices are calculated by netting the volumes of the lowest-priced financial and physical sold/bought contracts together and measuring the net volume at the weighted average "sold" price for the remaining financial and physical contracts.
Calculated using 194,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes and voluntary production shut-ins.
Futures market reflects AECO/NYMEX forward market prices as at March 8, 2010.

From time to time the Trust will enter into financial and forward physical gas sales arrangements to fix the basis differential between the NYMEX and AECO trading hubs. As of March 8, 2010 PET had no outstanding net position in basis differential contracts.

***Tax Horizon***

PET, and its principal operating entity POT, are taxable entities under the *Income Tax Act* (Canada) and are taxable only on income that is not distributed or distributable to the Unitholders. As the Trust distributes all of its taxable income to the Unitholders pursuant to the Trust Indenture and meets the requirements of the *Income Tax Act* (Canada) applicable to the Trust, PET does not expect to pay income taxes until the earlier of January 1, 2011 or if and when it ceases to be a trust. Legislation passed in June 2007 imposes a tax on distributions from entities such as the Trust, beginning generally on January 1, 2011. Commencing in January 2011 (provided that the Trust experiences only "normal growth" and no "undue expansion" before then) the Trust will be liable for tax on all income payable to Unitholders, which the Trust will not be able to deduct in computing its taxable income. (See "**GENERAL DEVELOPMENT OF BUSINESS –** Trust Tax Legislation")**.**

## REGULATORY RULINGS – GAS OVER BITUMEN

### Gas over bitumen royalty adjustments

The Alberta Energy and Utilities Board ("**AEUB**") issued General Bulletin 2003-28 ("**GB 2003-28**") and Shut-in Order 03-001 on July 22, 2003, establishing a process to identify gas production in the Wabiskaw-McMurray formations which may pose an unacceptable risk to the potential bitumen resource. The AEUB considers that gas production in pressure communication with associated potentially recoverable bitumen places future bitumen recovery at an unacceptable risk. Effective January 1, 2008, the AEUB was realigned into two separate regulatory bodies:

- the Energy Resources Conservation Board (**"ERCB"**), which regulates the oil and gas industry, and

- the Alberta Utilities Commission (**"AUC"**), which regulates the utilities industry.

All references to the AEUB in this annual information form refer to the previous Alberta Energy and Utilities Board. All references to ERCB refer to the Energy Resources Conservation Board.

Following the completion of a Regional Geological Study by the AEUB and an interim hearing held in March 2004 the AEUB ordered the shut-in, effective July 1, 2004, of Wabiskaw-McMurray natural gas production in northeast Alberta totalling approximately 123 MMcf/d. As of July 1, 2004, PET had shut-in wells producing approximately 17.2 MMcf/d pursuant to Decision 2004-045 and Interim Shut-in Orders 04-001 and 04-002 including 4.5 MMcf/d from the zones shut-in on September 1, 2003 pursuant to GB 2003-28 and Interim Shut-in Order 03-001. An additional 0.2 MMcf/d was shut-in September 1, 2004 pursuant to Decision 2004-064 and Interim Shut-in Order 04-003 related to wells in the Chard and Leismer areas.

On October 4, 2004 the Government of Alberta enacted amendments to the royalty regulation ("**Royalty Regulation**") with respect to natural gas. The amendments provide a mechanism whereby the government may prescribe additional royalty components to effect a reduction in the royalty calculated through the Crown royalty system for operators of gas wells which have been denied the right to produce by the AEUB as a result of recent bitumen conservation decisions. The Department of Energy issued Information Letter 2004-36 ("**IL 2004-36**") which, in conjunction with the Royalty Regulation, sets out the details of the gas over bitumen financial solution. In July 2005, further amendments to the Royalty Regulation were enacted with respect to natural gas, implementing a positive correction to the royalty calculation formula to provide a $0.05 per Mcf reduction in the effective operating costs adjustment. This effectively increases the net royalty adjustment by $0.025 per Mcf of deemed production and is retroactive to the date of shut-in. The revised formula for calculation of the royalty reduction provided in the Royalty Regulation is:

0.5 x ((deemed production volume x 0.80) x (Alberta Gas Reference Price - $0.3791/GJ))

Through this formula, operating costs are effectively deemed to be $0.40 per Mcf, royalties are deemed to be 20 percent, the deemed production is assigned the Alberta Gas Reference Price, which includes a transportation component and the entire formula is assigned an arbitrary 50 percent reduction factor.

The Trust's average net deemed production volume for purposes of the royalty adjustment was 19.9 MMcf/d for 2009. Deemed production represents all PET natural gas production shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the AEUB, or through correspondence in relation to an AEUB ID 99-1 application. In accordance with IL 2004-36, the deemed production volume related to wells shut-in is reduced by ten percent per year on the anniversary date of the shut-in order. Through subsequent consolidating acquisition activities in northeast Alberta, PET has increased its deemed production slightly despite the annual 10 percent decline. Current deemed production is approximately 18.7 MMcf/d.

In the second quarter of 2006, PET disposed of certain shut-in gas wells in the gas over bitumen area. As part of the disposition agreement, the Trust continues to receive the gas over bitumen royalty adjustments related to the sold wells, although the ownership of the natural gas reserves is transferred to the buyer. As such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer PET's responsibility.

Lease rental remission will also be granted for a mineral license or lease issued by the Crown that has a well or wells shut-in, according to IL 2004-036.

The phase 3 final hearing of GB 2003-28 was held between June 14, 2005 and August 12, 2005. We actively participated in the hearing, filing detailed evidence supporting the resumption of production from six gas pools representing approximately 8.5 MMcf/d of production which was shut-in pursuant to AEUB orders. We also reiterated to the AEUB our continued objection to all zones that had been shut-in as a result of the interim hearing based on the new evidence that we submitted.

On November 10, 2005 the AEUB issued Decision 2005-122 (the "**Final Decision**") regarding the phase 3 final hearing. The Final Decision had minimal impact on the Trust confirming the continued shut-in of the vast majority of the previously shut-in production. The Final Decision identified one additional well, producing less than 50 Mcf/d net to PET, for shut-in effective January 1, 2006. Shut-in PET wells with a total productive capacity of less than 200 Mcf/d net to PET were approved for production for a net gain to our production of approximately 150 Mcf/d as a result of the Final Decision.

On January 24, 2006, the AEUB held a meeting with industry to discuss the regulatory process that should be used to deal with three applications that were before the AEUB and the possible need for a broader bitumen conservation strategy in the Peace River and Cold Lake Oil Sands Areas of Alberta. Less than 5 percent of PET's current production comes from the Bluesky-Gething formations in the portion of the Panny field and the Darwin field which are located within the Peace River Oil Sands Area.

On April 4, 2006 the AEUB issued Bulletin 2006-14 announcing that it intended to conduct two separate hearings; one dealing with applications in the Cold Lake Oil Sands area, and another dealing with an application in the Peace River Oil Sands Area. The AEUB rejected the suggestion by industry that an industry/AEUB collaborative approach be undertaken prior to conducting any hearings. The AEUB believed that it would be more appropriate to first reach decisions on the specific applications. The AEUB also noted that it may be appropriate to undertake an industry/AEUB collaborative approach to assess the need for a broader bitumen conservation strategy in the Peace River and Cold Lake Oil Sands Areas following decisions on the hearings. The AEUB also noted the suggestion by several parties that the AEUB work with Alberta Energy to develop a financial assistance program for any wells that may be shut in. The AEUB considers this to be an issue beyond its jurisdiction.

On February 20, 2007, the AEUB commenced a hearing to address industry participants' request to shut-in a number of Clearwater natural gas wells within the Cold Lake Oil Sands Area. On July 24, 2007 the AEUB released Decision 2007-056 granting applications to deny production from and shut-in production from certain Clearwater natural gas wells in the Fisher and Moore areas. PET does not produce natural gas in the area identified in Decision 2007-056.

The hearing planned for the application in the Peace River Oil Sands Area was not held because the application was withdrawn. In its conclusions to Decision 2007-056 the AEUB indicated with respect to the need for broader bitumen conservation strategy in the Cold Lake and Peace River Oil Sands Areas, that since the AEUB had found it necessary to shut in gas, it believes there is a need to assess whether additional gas production should be curtailed in situations similar to those considered at the subject hearing. The specific process that should be used to conduct the assessment should be determined by the AEUB at a later time. It is possible that such a strategy, when drafted and implemented by the ERCB, will affect future natural gas production from reservoirs owned by the Trust and located within the gas over bitumen areas of concern. Decision 2007-056 did not specifically provide a timeline or process for arriving at a general bitumen conservation strategy. Gas production from a portion or all of these zones may be identified in the future as posing a potential concern with respect to communication with potentially recoverable bitumen resources. The Government of Alberta has not made comment as to whether the gas over bitumen royalty adjustment applied to shut-in gas in the Wabiskaw-McMurray in the Athabasca Oils Sands Area would apply to these other regions.

PET's Legend area produced gas from Wabiskaw-McMurray strata within the Athabasca Oil Sands Area. This gas was deemed by the AEUB, through the regional geological study released in early 2004, to not be in communication with potentially recoverable bitumen. October 16, 2009 PET announced that the ERCB issued Decision 2009-061 in response to applications by Sunshine Oilsands Ltd. and Total E&P Canada Ltd. for the shut-in of gas in the Liege Field (PET's Legend area) within the Athabasca Oil Sands Area. Having considered the evidence submitted to an interim hearing, the ERCB concluded that production of gas from 228 intervals in 158 wells may present a significant risk to future bitumen recovery, pending the outcome of the full hearing of the applications, currently scheduled for November 23, 2010. The Board also decided to shut in gas on an interim basis from 51 additional intervals in the Liege Wabiskaw A Pool, 15 additional intervals in the Liege Leduc A Pool, two additional intervals in the Liege Wabiskaw O Pool, and one additional interval in the Liege Wabiskaw M Pool. Gas production of approximately 8.6 MMcf/d from a total of 70 wells was shut-in by the Trust effective October 31, 2009, pursuant to Decision 2009-061.

In 2009 the Trust received $10.4 million in gas over bitumen royalty adjustments, of which $2.7 million was classified as revenue and $7.7 million was recorded on the Trust's balance sheet as a liability. Gas over bitumen royalty adjustments are not paid to PET in cash, but are a deduction from the Trust's monthly natural gas royalty invoices. In periods of exceptionally low gas prices, such as those experienced in the second half of 2009, the Trust's net crown royalty expenses are close to zero, and as such the royalty adjustments are not received immediately. Eventual realization of the royalty adjustments is highly likely as deemed production is reduced by ten percent annually. PET has a total of $5.1 million in royalty adjustments receivable as at December 31, 2009, which are netted against the gas over bitumen liability on the Trust's balance sheet. These amounts are included in funds flows and considered distributable income. Cumulative royalty adjustments received to December 31, 2009 total $108.7 million.

PET continues to focus on converting its shut-in natural gas reserves back into producing assets. While the Trust is receiving partial relief for its lost cash flow in the form of monthly royalty reductions, PET still owns the shut-in reserves and believes them to be more valuable if returned to production. PET closely monitors new information from subsurface bitumen exploitation projects as there is potential that future field evidence from actual SAGD projects will provide support to PET's technical position. The Trust is actively involved in technical solution initiatives.

## RISK FACTORS

**A discussion of PET's risk factors is contained in the section "Risk Factors" in the Trust's management's discussion and analysis for the year ended December 31, 2009 ("MD&A"), which section is incorporated by reference herein. Investors should carefully consider the risk factors set out in the MD&A and consider all other information contained herein and in the Trust's other public filings before making an investment decision.**

## RECORD OF CASH DISTRIBUTIONS

We distribute cash to Unitholders out of the income and other amounts we receive, indebtedness of POT to us, our other assets and other investments, less expenses and any other amounts we are permitted to deduct or must withhold or pay to third parties. We borrow funds from time to time to finance the purchase of properties or corporate entities, for capital expenditures or for other financial obligations or expenditures in respect of properties held by us or for working capital purposes. The credit facilities contain provisions which restrict the ability of the Trust to pay distributions to Unitholders in the event of the occurrence of certain events of default.

The historical distributions described below may not be reflective of future distributions, which will be subject to review by the board of directors of the Administrator taking into account the prevailing circumstances at the relevant time. (See "**RISK FACTORS")**.

The accompanying table summarizes cash distributions to Unitholders for each of the last three years:

| For the Period Ended | Payment Date | Distribution per Trust Unit |
|---|---|---|
| **2007** | | |
| January 31, 2007 | February 15, 2007 | $0.200 |
| February 28, 2007 | March 15, 2007 | $0.140 |
| March 31, 2007 | April 16, 2007 | $0.140 |
| April 30, 2007 | May 15, 2007 | $0.140 |
| May 31, 2007 | June 15, 2007 | $0.140 |
| June 30, 2007 | July 16, 2007 | $0.140 |
| July 31, 2007 | August 15, 2007 | $0.100 |
| August 31, 2007 | September 17, 2007 | $0.100 |
| September 30, 2007 | October 15, 2007 | $0.100 |
| October 31, 2007 | November 15, 2007 | $0.100 |
| November 30, 2007 | December 17, 2007 | $0.100 |
| December 31, 2007 | January 15, 2008 | $0.100 |

| | | |
|---|---|---|
| **2008** | | |
| January 31, 2008 | February 15, 2008 | $0.100 |
| February 29, 2008 | March 17, 2008 | $0.100 |
| March 31, 2008 | April 15, 2008 | $0.100 |
| April 30, 2008 | May 15, 2008 | $0.100 |
| May 31, 2008 | June 16, 2008 | $0.100 |
| June 30, 2008 | July 15, 2008 | $0.100 |
| July 31, 2008 | August 15, 2008 | $0.100 |
| August 31, 2008 | September 15, 2008 | $0.100 |
| September 30, 2008 | October 15, 2008 | $0.100 |
| October 31, 2008 | November 17, 2008 | $0.100 |
| November 30, 2008 | December 15, 2008 | $0.100 |
| December 31, 2008 | January 15, 2009 | $0.100 |
| **2009** | | |
| January 31, 2009 | February 17, 2009 | $0.070 |
| February 28, 2009 | March 16, 2009 | $0.070 |
| March 31, 2009 | April 15, 2009 | $0.050 |
| April 30, 2009 | May 15, 2009 | $0.050 |
| May 31, 2009 | June 15, 2009 | $0.050 |
| June 30, 2009 | July 15, 2009 | $0.050 |
| July 31, 2009 | August 17, 2009 | $0.050 |
| August 31, 2009 | September 15, 2009 | $0.050 |
| September 30, 2009 | October 15, 2009 | $0.050 |
| October 31, 2009 | November 16, 2009 | $0.050 |
| November 30, 2009 | December 15, 2009 | $0.050 |
| December 31, 2009 | January 15, 2010 | $0.050 |
| **2010** | | |
| January 31, 2010 | February 16, 2010 | $0.050 |
| February 28, 2010 | March 15, 2010 | $0.050 |

## MARKET FOR SECURITIES

Our Trust Units are listed and posted for trading on the TSX under the symbol **PMT.UN**. The following table sets out the price range and trading volume of Trust Units as reported by the TSX for the periods indicated.

| PMT.UN<br>Period | High | Low | Volume |
|---|---|---|---|
| **2009** | | | |
| January | 5.56 | 4.95 | 6,151,442 |
| February | 4.67 | 3.60 | 7,319,978 |
| March | 3.55 | 2.71 | 8,772,738 |
| April | 3.89 | 3.28 | 7,597,678 |
| May | 4.50 | 3.49 | 8,701,735 |
| June | 4.92 | 4.22 | 7,806,941 |
| July | 4.52 | 4.00 | 8,009,721 |
| August | 4.95 | 4.18 | 8,311,052 |
| September | 5.50 | 4.49 | 8,851,875 |
| October | 5.81 | 5.10 | 7,950,419 |
| November | 5.23 | 4.57 | 8,158,332 |
| December | 5.22 | 4.62 | 6,083,498 |
| **2010** | | | |
| January | 5.57 | 4.89 | 8,594,978 |
| February | 5.14 | 4.93 | 6,405,897 |

The Trust's 6.25 percent Convertible Debentures ("**6.25% Convertible Debentures**") are listed and posted for trading on the TSX and trade under the symbol **PMT.DB.A**. The following sets out the price range and trading volume of the 6.25% Convertible Debentures as reported by the TSX for the periods indicated**.**

| PMT.DB.A<br>Period | High | Low | Volume |
|---|---|---|---|
| **2009** | | | |
| January | 94.00 | 90.00 | 3,870,000 |
| February | 91.00 | 87.00 | 7,060,000 |
| March | 90.00 | 85.00 | 5,890,000 |
| April | 99.75 | 88.75 | 10,400,000 |
| May | 100.00 | 98.50 | 3,940,000 |
| June | 100.00 | 98.00 | 8,650,000 |
| July | 100.05 | 99.00 | 9,380,000 |
| August | 100.75 | 99.8 | 7,990,000 |
| September | 100.01 | 99.00 | 9,350,000 |
| October | 101.50 | 97.00 | 16,580,000 |
| November | 99.00 | 92.00 | 9,260,000 |
| December | 100.25 | 98.00 | 23,780,000 |
| **2010** | | | |
| January | 101.50 | 100.00 | 6,640,000 |
| February | 101.00 | 100.26 | 4,175,000 |

The 7.25% Convertible Debentures are listed and posted for trading on the TSX and trade under the symbol PMT.DB.D. The following sets out the price range and trading volume of the 7.25% Convertible Debentures as reported by the TSX for the periods indicated. The 2006 6.25% Convertible Debentures were listed and posted for trading on the TSX and traded under the symbol PMT.DB.B up until December 17, 2009. See "Three Year History – Year Ended December 31, 2009 – Convertible Debenture Amendments". The table above sets out the price range and trading volume of the 6.25%

Convertible Debentures as reported by the TSX for the periods indicated up to December 17, 2009, as well as the price range and trading volume of the 7.25% Convertible Debentures (listed and posted for trading on the TSX under the symbol PMT.DB.D) as reported by the TSX for the periods thereafter.

**PMT.DB.B**

| **Period** | **High** | **Low** | **Volume** |
|---|---|---|---|
| **2009** | | | |
| January | 84.99 | 70.00 | 6,020,000 |
| February | 83.00 | 72.26 | 7,760,000 |
| March | 79.98 | 70.00 | 4,640,000 |
| April | 81.00 | 73.50 | 25,010,000 |
| May | 90.00 | 82.00 | 4,130,000 |
| June | 96.00 | 90.00 | 45,920,000 |
| July | 97.75 | 91.00 | 5,430,000 |
| August | 99.99 | 95.00 | 11,950,000 |
| September | 99.99 | 98.00 | 63,460,000 |
| October | 99.00 | 95.00 | 27,480,000 |
| November | 98.25 | 92.06 | 24,730,000 |
| December 16, 2009 | 99.95 | 97.31 | 32,000,000 |

**PMT.DB.D**

| **Period** | **High** | **Low** | **Volume** |
|---|---|---|---|
| **2009** | | | |
| December 17, 2009 | 105.00 | 98.00 | 3,150,000 |
| **2010** | | | |
| January | 104.25 | 100.40 | 28,620,000 |
| February | 102.00 | 100.35 | 23,330,000 |

The 6.50% Convertible Debentures are listed and posted for trading on the TSX and trade under the symbol **PMT.DB.C.** The following sets out the price range and trading volume of the 6.50% Convertible Debentures as reported by the TSX for the periods indicated.

**PMT.DB.C**

| **Period** | **High** | **Low** | **Volume** |
|---|---|---|---|
| **2009** | | | |
| January | 82.50 | 59.00 | 28,100,000 |
| February | 75.00 | 68.00 | 79,370,000 |
| March | 70.00 | 62.01 | 12,700,000 |
| April | 78.6 | 70.00 | 17,020,000 |
| May | 85.95 | 78.00 | 70,420,000 |
| June | 90.00 | 84.50 | 16,160,000 |
| July | 90.25 | 87.10 | 8,000,000 |
| August | 94.00 | 91.50 | 15,890,000 |
| September | 98.88 | 93.00 | 28,190,000 |
| October | 97.25 | 94.50 | 27,410,000 |
| November | 96.71 | 95.00 | 48,940,000 |
| December | 100.00 | 95.35 | 27,440,000 |
| **2010** | | | |
| January | 102.70 | 99.90 | 18,055,000 |
| February | 103.85 | 102.40 | 14,140,000 |

# DESCRIPTION OF CAPITAL STRUCTURE

## General Description of Capital Structure

We are authorized to create and issue an unlimited number of Trust Units and an unlimited number of special voting units ("Special Voting Units") described below. We are authorized to create, issue, sell and deliver Trust Units, including rights, warrants, special warrants, subscription receipts, instalment receipts, exchangeable securities or other securities to purchase, convert, redeem or exchange into Trust Units or other securities, including debt convertible into Trust Units or other securities of PET, on such terms and conditions as the Administrator may determine. All Trust Units outstanding from time to time are entitled to receive an equal undivided share of any distributions from the Trust. In the event that PET ceases to exist or is wound up, each Trust Unit entitles its holder to an equal undivided share in any amounts distributed upon such cessation or winding-up after satisfaction of all liabilities and provision for indemnities. All Trust Units are of the same class with equal rights and privileges. Each Trust Unit is transferable, fully paid and non-assessable and entitles its holder to receive notice of, attend and vote at all meetings of the Unitholders. The Trust Units do not entitle the Unitholder to any conversion, retraction, redemption or pre-emptive rights, except for the rights referred to under **Redemption Right**. No fractional Trust Units will be issued or transferred except for the purposes of distributions of Trust Units referred to in **Distributions**.

In order to allow us flexibility in pursuing corporate acquisitions, the Trust Indenture allows for the creation and issuance of Special Voting Units. If and when we issue Special Voting Units, it will likely be to a trustee for the benefit of the holders of securities which are exchangeable for Trust Units, entitling the trustee to such number of votes at meetings of Unitholders as the Administrator's board of directors ("Board" or "Board of Directors") may prescribe. The Special Voting Units give us the flexibility to acquire the securities of another issuer in exchange for securities that are ultimately exchangeable for Trust Units. The Board will set the voting rights or other rights and the terms upon which we issue Special Voting Units. The Special Voting Units will not entitle the holder to any distributions of any nature whatsoever from PET or to any beneficial interest in any of our assets during PET's existence or upon PET's termination or winding-up. To the extent that we issue Special Voting Units, the voting power of existing Unitholders will be reduced.

The legal ownership of our assets and the right to conduct the undertaking of PET, subject to the limitations contained in the Trust Indenture, are vested exclusively in the Trustee or such other person as the Trustee determines. The Trust Units are personal property and confer upon Unitholders only the interest and rights specifically set forth in the Trust Indenture. Except as specifically set out in the Trust Indenture, no Unitholder has or is deemed to have any right of ownership in any of our assets. Under the Trust Indenture material amendments to the Trust Indenture affecting the rights of Unitholders require the approval of Unitholders by a resolution passed at a meeting of Unitholders by more than 66⅔ percent of the votes cast ("**Special Resolution**").

The Trust Units do not represent a traditional investment and you should not view them as "shares" in PET. (See "**RISK FACTORS")**.

**The Trust Units are not "deposits" within the meaning of the *Canada Deposit Insurance Corporation Act* (Canada) and are not insured under the provisions of that act or any other legislation. Further, none of PET, POT or the Administrator is a trust company and, accordingly, none of them are registered under any trust and loan company legislation as they do not carry on, or intend to carry on, the business of a trust company.**

## Constraints For Non-Resident Unitholders

In order for us to maintain our status as a mutual fund trust under the *Income Tax Act* (Canada), we must not be established or maintained primarily for the benefit of persons who are non-residents of Canada for the purposes of the *Income Tax Act* (Canada), including any Unitholder that is a partnership, any member of which is neither a resident or deemed to be a resident in Canada for the purposes of the Income Tax Act, (referred to in this section as "Non-Residents"). The Trust Indenture contains restrictions on the ownership of Trust Units by Unitholders who are Non-Residents. We may require Unitholders to provide a declaration (referred to in this section as a "Residence Declaration") specifying whether or not they are Non-Residents. If, at any time, the trustee determines that the beneficial owners of 49 percent or more of the Trust Units are or may be Non-Residents or that such a situation is imminent, the trustee may announce publicly such determination. After such determination the trustee will refuse any subscription or transfer not accompanied by a Residence Declaration confirming Canadian residence. If the trustee determines that Non-Residents hold a majority of the Trust Units, the trustee may send a notice to non-resident requiring them to sell all or a portion of their Trust Units within 60 days. The trustee will send notices only to as many Non-Resident Unitholders and with respect to only so many Trust Units as may be reasonably necessary to ensure that the number of Trust Units held by Non-Residents would be reduced, as far as the trustee is aware, to no greater than 48 percent of the Trust Units then outstanding. The trustee will use reasonable commercial efforts to ensure that its actions in this regard will not reduce the number of Trust Units held by Unitholders who are or may be Non-Residents, so far as the trustee is aware, to less than 40 percent of the Trust Units outstanding. Following the 60 days, to the extent non-resident Unitholders have not sold the specified number of Trust Units, the trustee may sell Trust Units on the Non-Residents' behalf unless the Non-Residents provide satisfactory evidence that they are Canadian residents. Until the trustee sells such Trust Units, the trustee will suspend the voting and distribution rights associated with those Trust Units. The trustee will sell the Trust Units on any stock exchange on which the Trust Units are then listed. Such Trust Units will be sold on the basis of an inverse order to the order of acquisition by such Non-Residents until the trustee, in its sole discretion, determines that the restrictions on ownership imposed on PET are no longer in danger of being violated. The trustee will pay the net proceeds of such sale to the Non-Resident upon the Non-Resident's surrender of its form of certificate representing the Trust Units (the “Unit Certificate”).

**Ratings**

None of our securities have been formally rated by any accredited rating agency.

**Unitholder Liability**

The Trust Indenture provides that no Unitholder, in its capacity as such, will be subject to any liability to any person:

- in connection with our assets, obligations or affairs; or
- with respect to any act any person performs pursuant to the Trust Indenture; or
- with respect to any act or omission of any person in the performance or exercise, or purported performance or exercise, of any obligation, power, discretion or authority conferred under the Trust Indenture; or
- with respect to any transaction any person enters into pursuant to the Trust Indenture.

Further, Unitholders, in their capacities as such, are not contractually liable to indemnify any person for any of the above liabilities, including taxes any person may incur on our behalf. If, however, a court assesses any of such liabilities against a Unitholder, those liabilities will be enforceable only against and will only be satisfied out of our assets. We will be liable to the Unitholders and indemnify the Unitholders, to the extent of our assets, from liability arising as a result of the Unitholders not having such limited liability. The Trust Indenture provides that every written contract entered into, by, or on our behalf must include a provision substantially to the effect that any obligation created under such contract will not be binding upon Unitholders personally.

**Notwithstanding the terms of the Trust Indenture, Unitholders, in their capacities as such, may not have the same protection from our liabilities that a shareholder would have from the liabilities of a corporation. Unitholders may face personal liability for claims against us, including contract claims, tort claims, environmental claims, claims for taxes and possibly other statutory liabilities. Unlike many other royalty trusts and income funds, our structure does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to Unitholders.**

Note, however, that on July 1, 2004 the *Income Trust Liability Act* (Alberta) came into force creating a statutory limitation on the liability of Unitholders of Alberta income trusts such as the Trust. The legislation provides that a Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee. The implementation of the *Income Trust Liability Act* (Alberta) assists in mitigating the effect of the Trust's structure and its lack of an inter-positioned limited liability entity for claims after July 1, 2004. To PET's knowledge, this legislation has not been subject to interpretation by courts in the Province of Alberta.

We intend to conduct our business so as to avoid, as far as reasonably possible, any material risk of liability to the Unitholders for claims against us. We have obtained insurance, in amounts available and appropriate, for the operations of POT and the Administrator. However, the amounts and types of insurance obtained may not be sufficient to provide full coverage.

**Distributions**

We distribute cash to the Unitholders out of the income and other amounts we receive from any royalties, indebtedness of POT to PET, our other assets and other investments, less expenses and any other amounts we are permitted to deduct or must withhold or pay to third parties.

The material sources of our cash flow are currently limited to:

- royalty income we receives on the POT Royalty;
- interest and principal POT pays respecting indebtedness of POT to us from time to time to finance our operations; and
- trust income POT distributes to us as its sole beneficiary.

Our material expenses are currently substantially limited to:

- interest, principal and fees paid to its lenders;
- trustee fees and expenses;
- expenses related to printing and other matters in connection with communicating with and sending distributions to the Unitholders; and
- general and administrative expenses.

POT may apply some or all of its cash flow to capital expenditures to develop POT's oil and natural gas properties or to acquire additional oil and natural gas properties. This would effectively reduce the amounts POT pays to us under the POT Royalty as well as reduce POT's distributions to us as its sole beneficiary and our distributions to Unitholders. Under the terms of our credit facility, if our lenders determine the borrowing base has been exceeded, we will be precluded from providing distributions on the Trust Units until the borrowing base is no longer in a shortfall position. Our lenders may also restrict our ability to pay distributions in circumstances when we are in breach or default of our agreements.

We pay such cash distributions on or about the 15th day of each month or, if such day is not a business day, the next following business day. Each Unitholder has the right to enforce payment of any distribution at the time the amount becomes payable. Any of our income (as computed under the *Income Tax Act* (Canada) or net realized capital gains not otherwise distributed to Unitholders in a calendar year shall, without any further action on the part of the Administrator, be due and payable to Unitholders of record at the close of business on December 31 in each year. Absent a demand from a Unitholder to enforce payment, such amounts will be paid to Unitholders on or before February 15 of the following year. Upon the Administrator's written direction, the Trustee may change the dates on which we pay distributions, at any time, subject to having given the Unitholders not less than 60 days prior written notice. Additionally, upon the Administrator's written direction, the Trustee may change the record date for the payment of distributions at any time, upon compliance with any requirements of applicable law or the rules of any stock exchange.

Where:

- between record dates for distributions, we have paid cash in respect of Trust Units tendered for redemption (see **Redemption Right**), we may, on the next distribution date, reduce the cash amount of the aggregate distribution at that time by the cash amount paid for the redemptions and include a distribution to Unitholders of additional Trust Units in place of that amount; and

- we determine we do not have sufficient cash to pay the full distribution to be made on a distribution date (or on any other date on which any other distribution is payable under the Trust Indenture), or if any cash distribution would be contrary to, or would not allow the Trustee to comply with, its credit facilities, the distribution may, at the option of the Administrator, include a distribution to Unitholders of additional Trust Units having a value equal to the cash shortfall and the amount of cash distributed will be reduced by the cash shortfall.

After any such distribution we may consolidate the Trust Units so that each Unitholder has the same number of Trust Units as they held immediately prior to such distribution except where tax is required to be withheld in respect of the Unitholder's share of the distribution. The value of such additional Trust Units will be based on the closing trading price thereof on the principal stock exchange on which they are listed on the applicable distribution date or otherwise as the Trustee determines. The net effect of the foregoing is that Unitholders would not receive all or a portion of the cash which would have been distributed to them, with no corresponding increase in their ownership percentage in PET. Where amounts so distributed represent income, Non-Resident Unitholders will be subject to withholding tax and the consolidation will not result in such Non-Resident Unitholders holding the same number of Trust Units. Such Non-Resident Unitholders will be required to surrender the Unit Certificate (if any) representing their original Trust Units in exchange for a certificate respecting their post-consolidation Trust Units.

The Trust Indenture provides that the Trustee may deduct or withhold from any amounts payable to Unitholders, including payments or deliveries due to Unitholders who have exercised redemption rights, amounts required by law to be withheld from those payments. If withholding is required on any distributions (including distributions of Trust Units) or redemption amounts and the Trustee is or was unable to withhold, or otherwise did not withhold, taxes from a particular payment, the Trustee is permitted to withhold the applicable amounts from other distributions to the Unitholder or sell such number of Trust Units being distributed to Unitholders as are necessary to satisfy the Trustee's withholding tax obligations with respect to the Unitholder and all of the Trustee's reasonable expenses with respect thereto.

**Redemption Right**

Unitholders may redeem their Trust Units at any time by delivering their Unit Certificates to the Trustee, together with a properly completed notice requesting redemption in a form acceptable to us. Once we have received all required documents, Unitholders have no rights with respect to the Trust Units tendered for redemption, other than a right to receive the redemption amount, which amount per Trust Unit will be the lesser of 90 percent of the weighted average trading price of the Trust Units on the principal market on which they are traded for the 10 day period after the Trust Units have been validly tendered for redemption and the “closing market price” of the Trust Units. The redemption amount will be payable on the last day of the following calendar month. The “closing market price” will be the closing price of the Trust Units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or, if there was no trade of the Trust Units on that date, the average of the last bid and ask prices of the Trust Units on that date.

In the event that the aggregate redemption value of Trust Units tendered for redemption in a calendar month exceeds $100,000 and the Administrator does not exercise its discretion to waive such $100,000 limit, we will not use cash to pay the redemption amount for any of the Trust Units tendered for redemption in that month. Instead, we will pay the redemption amount for those Trust Units, subject to compliance with applicable laws, including securities laws, of all jurisdictions, and the receipt of all applicable regulatory approvals, by the issuance of promissory notes of PET (referred to in this section and elsewhere as the “Notes” or the “PET Notes”) to the tendering Unitholders on the last day of the next calendar month. The Notes will have an aggregate principal amount equal to the aggregate redemption amount of the Trust Units tendered by the Unitholder for redemption. If applicable laws prevent the issuance of these Notes to a Unitholder, the Trustee will authorize the payment of the redemption amount to that Unitholder in future months. Under the terms of our credit facility, if our lenders determine the borrowing base has been exceeded or we are in breach or default of our agreements, we will be precluded from paying cash for redemptions of Trust Units.

Notwithstanding the above, if, at the time Trust Units are tendered for redemption:

- in the discretion of the Administrator, the trading price of the Trust Units on the stock exchange on which the Trust Units are listed does not represent the fair market value of the Trust Units; or

- the normal trading of the Trust Units on the stock exchange on which they are listed is suspended or halted on the date the Trust Units are tendered for redemption or for more than five trading days during the ten trading day period after that date;

the redemption amount for each of those Trust Units will be equal to 90 percent of the fair market value thereof as determined by the Administrator. We will pay such redemption amount on the last day of the third month following the month in which those Trust Units were tendered for redemption. At our option, we will pay the redemption amount in cash or, subject to compliance with applicable laws, including securities laws, of all jurisdictions, and the receipt of all applicable regulatory approvals, the delivery to the Unitholder of PET Notes having an aggregate principal amount equal to the aggregate redemption amount of the Trust Units tendered by the Unitholder for redemption.

The Notes delivered as set out above will be unsecured and bear interest at a market rate of interest to be determined at the time of issuance by the Board of Directors, based on the advice of an independent financial advisor, with the interest to be payable monthly. The Notes will be subordinated and, in certain circumstances, postponed to all our indebtedness. Subject to prepayment, the Notes will be due and payable 5 years after issuance.

The Notes will be issued under and subject to the terms of a note indenture to be entered into prior to their issuance which indenture may provide for the issuance of Notes in series or otherwise. The trustee under the note indenture will be obligated under an agreement with our lenders to subordinate, and in certain circumstances to postpone, the payment of such Notes. Such Notes may not be qualified investments for trusts governed by registered retirement savings plans, registered retirement income funds, registered education savings plans and deferred profit savings plans if we cease to qualify as a mutual fund trust under the *Income Tax Act* (Canada) or if the Trust Units cease to be listed.

The Trustee has the discretion to designate a portion of any redemption payment as income, however, any portion designated as income will not reduce the amount of any declared and unpaid income distribution that the Unitholder may be entitled to receive at the time of redemption. In such case, the Unitholder would receive full payment of both the redemption amount (however designated) and the unpaid income distribution.

We expect that the redemption right will not be the primary mechanism for holders of Trust Units to dispose of their Trust Units. We will not list the Notes referred to above on any stock exchange and no market will exist for them. The Notes may be subject to resale restrictions under applicable securities laws.

## ESCROWED SECURITIES AND SECURITIES SUBJECT TO CONTRACTUAL RESTRICTION ON TRANSFER

To the knowledge of the Administrator, none of our securities are held in escrow or subject to a contractual restriction on transfer.

## DIRECTORS AND OFFICERS

The directors and officers of the Administrator are set out in the table below as are their province and country of residence and present positions with the Administrator and their principal occupations during the five preceding years:

| Name and Province and Country of Residence | Position held with the Administrator and Period Served as a Director | Principal Occupations During the Past Five Years |
|---|---|---|
| **Clayton H. Riddell**<br>Alberta, Canada | Chairman of the Board and Director since June 28, 2002 | Mr. Riddell has been the Chairman of the Board and Chief Executive Officer of Paramount Resources Ltd. ("PRL") since 1978. Until June 2002 he was also the President. He is currently Chairman of the Board of the Administrator and prior thereto was the Chairman and Chief Executive Officer of the Administrator. He graduated from the University of Manitoba with a Bachelor of Science (Honours) Degree in Geology and is currently a member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta, the Canadian Association of Petroleum Producers, the Canadian Society of Petroleum Geologists, and the American Association of Petroleum Geologists. |
| **Susan L. Riddell Rose**(4)<br>Alberta, Canada | President, Chief Executive Officer and Director since June 28, 2002 | Ms. Riddell Rose has been the President and Chief Executive Officer of the Administrator since May 9, 2005. Prior to that time, Ms. Riddell Rose was the President and Chief Operating Officer of the Administrator since June 28, 2002. Prior to her current occupation, Ms. Riddell Rose was employed by Paramount Resources Ltd., culminating in the position of Corporate Operating Officer. She has also been a director of Paramount Resources Ltd. since 2000. Ms. Riddell Rose also sits on the Board of Directors of Newalta Corporation. |
| **Cameron R. Sebastian**<br>Alberta, Canada | Vice President, Finance and Chief Financial Officer | Vice President, Finance and Chief Financial Officer of the Administrator since June 28, 2002. Prior to his current occupation, Mr. Sebastian was Vice President, Finance of Summit Resources Limited from June 2000 to June 2002. Prior to that, he was Vice President, Finance of Pursuit Resources Corp. |
| **Jeffrey R. Green**<br>Alberta, Canada | Vice President, Production Operations | Vice President, Production Operations of the Administrator since January 30, 2009. Prior to his current position Mr. Green was Manager, Acquisitions & Divestitures of the Administrator from April 1, 2007 to January 30, 2009. Prior to that he held position as was Exploitation Manager and Production Manager at Anadarko Canada Corporation. |
| **Gary C. Jackson**<br>Alberta, Canada | Vice President, Land, Legal and Acquisitions | Vice President, Land, Legal and Acquisitions of the Administrator since June 28, 2002. Prior to his current occupation, Mr. Jackson was Vice President, Land of Summit Resources Limited from May 2000 to June 28, 2002. Prior to that, he was Manager of Acquisitions and Divestitures, Joint Venture Mid-Stream Services at Petro-Canada Oil & Gas. |
| **Kevin J. Marjoram**<br>Alberta, Canada | Vice President, Engineering Execution | Vice President, Engineering Execution of the Administrator since November 1, 2008. Prior to his current position Mr. Marjoram was Vice President Engineering and Operations of the Administrator from June 28, 2002 to October 31, 2008. Prior to that, Mr. Marjoram was Engineering Manager, Northeast Alberta West Side for Paramount Resources Ltd. from July 2000 to June 2002. Prior to that, he held positions in an operations managerial capacity for Spire Energy Ltd. and Northrock Resources Ltd. |

| Name and Province and Country of Residence | Position held with the Administrator and Period Served as a Director | Principal Occupations During the Past Five Years |
|---|---|---|
| **Marcello M. Rapini**<br>Alberta, Canada | Vice President, Marketing | Vice President, Marketing of the Administrator since December 7, 2006. Prior to his current occupation, Mr. Rapini worked for the Administrator from December 15, 2005 as Manager, Marketing. From November 2004 to November 2005 Mr. Rapini was Senior Trader with Eagle Energy Marketing Canada. From 2003 to 2004 he worked as a Senior Trader and Vice President Trading with Sempra Energy Trading, and from 1996 to 2002 was Senior Trader with Mirant Energy Marketing Ltd. |
| **Roderick P. Warters**<br>Alberta, Canada | Vice President, Geoscience and New Ventures | Vice President, Geoscience and New Ventures of the Administrator since September 4, 2007. Mr. Warters joined Petro-Canada in 1996 as their Chief Geophysicist and later held the position of Northern Exploration Manager. In 2001 he joined Burlington Resources as the Vice President of Exploration for Canada, and after their merger in 2006 he assumed the position of Senior Vice President of Exploration for ConocoPhillips Canada. Mr. Warters has held a number of technical and management positions in other organizations including Amerada Hess and Dome Petroleum. |
| **J.C. Strong**<br>Alberta, Canada | Corporate Secretary and Corporate Counsel | Corporate Secretary and Corporate Counsel of the Administrator since May 7, 2009, Acting Corporate Secretary and Corporate Counsel of the Administrator from September 2006 forward. Mr. Strong practiced with the law firm of Gunn & Prithipaul from June 1996 until January 2002, and thereafter worked as a sole practitioner up until joining Alaris Income Growth Fund as counsel in December 2005. |
| **Karen A. Genoway**(2)(3)(5)(7)<br>Alberta, Canada | Director since June 28, 2002 | Ms. Genoway is a professional landman with over 28 years experience in the oil and natural gas industry. Currently, she is the Vice President, Land Onyx 2006 Inc., a private company. From February 2001 she was Vice President of Request Management Inc., manager of Request Income Trust until its acquisition by Pulse Data Inc. in January 2002. Ms. Genoway was with the Enerplus Resources Fund where she held the positions of Senior Vice President (1997 to 2000), Vice President Land (1989 to 1997) and Land Manager (1987 to 1989). Ms Genoway is a graduate of the ICD Corporate Governance College, Directors Education Program, February 2006 and received her accreditation from the Institute of Corporate Directors, Institute-Certified Director, ICD.D, April 2006. |
| **Randall E. Johnson**(1)(3)(5)(7)<br>Alberta, Canada | Director since June 20, 2006 | Mr. Johnson has been an independent businessman since 2005. Prior to that he was Managing Director of the Bank of Montreal's Corporate Banking group from 1996 to 2005, having been with the Bank of Montreal since 1984. Mr. Johnson has served on the Board of Directors of Atlas Energy Ltd. (May 2005 to December 2006) and Dual Exploration Inc. (June 2005 to November 2006). Since January 2007 Mr. Johnson has also been a director of Magellan Resources Ltd., a privately held oil and gas company. |

| Name and Province and Country of Residence | Position held with the Administrator and Period Served as a Director | Principal Occupations During the Past Five Years |
|---|---|---|
| **Robert A. Maitland**[(1)(3)(5)(7)] Alberta, Canada | Director since February 7, 2008 | Mr. Maitland is a Chartered Accountant with over 30 years of senior business experience, primarily in the oil and gas industry. Mr. Maitland was most recently the Vice President Finance and Chief Financial Officer of Fairquest Energy Ltd. (June 2005 to June 2007) and Fairborne Energy Ltd. (May 2002 to May 2005). He has also been the Vice President and Chief Financial Officer for Canadian Midstream Services Ltd. (April 1999 to May 2001), Summit Resources Ltd., Omega Hydrocarbons Ltd., Shiningbank Energy Income Fund, Post Energy Ltd., and Pan East Petroleum Corp. He presently serves on the board of directors of Developmental Disabilities Resources Centre and several other private companies. |
| **Donald J. Nelson**[(2)(4)(7)] Alberta, Canada | Director since June 28, 2002 | Mr. Nelson is President of Fairway Resources Inc., an oil and gas consulting firm. Fairway Resources Inc. was retained as consultant for Hawker Resources Inc. from November 25, 2004 to March 22, 2005. During this time Mr. Nelson was acting Senior Vice President and Chief Operating Officer of Hawker Resources Inc. Prior to his current occupation, Mr. Nelson held the consecutive positions of Vice President, Operations and President and Director with Summit Resources Limited from July 1996 to June 2002. He is an active member of the Association of Professional Engineers, Geologists and Geophysicists of Alberta and of the Society of Petroleum Engineers. |
| **John W. (Jack) Peltier**[(1)(2)(4)(7)] Alberta, Canada | Director since June 28, 2002 | Since 1978, Mr. Peltier has been the President of Ipperwash Resources Ltd., a private investment company. He was Chairman of the Board of Trustees of Request Income Trust (March 2001 to January 2002); director and then Chairman of the Board of EnerMark Inc. and concurrently of the Board of Trustees of EnerMark Income Fund (1986 to June 2001); director of Enerplus Resources Corporation and concurrently a member of the Board of Trustees of Enerplus Resources Fund (May 2000 to June 2001); and director of Thunder Energy Ltd. (and Thunder Energy Trust) (October 1995 to May 2006). Mr. Peltier has also been a director of the following public corporations: Courage Energy Inc. (November 2000 to July 2001), Bow Valley Energy (May 2005 – April 2009)and Manhattan Resources Ltd. (October 2001 to January 2003). |
| **Howard R. Ward**[(3)(4)(5)(7)] Alberta, Canada | Director since June 28, 2002 | Mr. Ward has been a partner with International Energy Counsel LLP, a law firm, since December 2002. Prior thereto, Mr. Ward was counsel with the law firm McCarthy Tétrault LLP from June 2002 to December 2002. Prior to that, he was counsel with Donahue and Partners LLP and, for more than 22 years, partner with Burstall Ward (now Burstall Winger LLP), Barristers and Solicitors. He has been a member of the Law Society of Alberta since 1975. He also has served as a director of the following publicly traded entities: Blue Sky Resources Ltd. (July 1999 to July 2000); Cabre Exploration Ltd. (June 1981 to December 2000); Jet Energy Corp. (August 1995 to November 1999); and Tuscany Resources Ltd.,(October 1997 to October 2001). |

Member of the Audit Committee
Member of the Reserves Committee.
Member of the Corporate Governance Committee.
Member of the Environmental, Health and Safety Committee.
Member of the Compensation Committee.
The terms of office of all directors of the Administrator will expire on the date of the next annual Unitholders' meeting of the Administrator.
Ms. Genoway , Mr. Johnson, Mr. Maitland, Mr. Nelson, Mr. Peltier, Mr. Ward and are independent, non-employee directors.

The directors and officers of the Administrator, as a group, beneficially own or control or direct, directly or indirectly an aggregate of 29,644,967 voting securities as of March 9, 2010 representing 23.2% percent of the outstanding Trust Units.

Each of the senior officers listed above devote their full time efforts to POT, PET and the Administrator.

**Corporate Cease Trade Orders, Bankruptcies, Penalties or Sanctions**

From 1997 to 2003, Mr. Maitland was a director of Military International Ltd. which was cease traded for failure to file financial statements, which order (in this section, "order" has the meaning attributed to it in **NI 51-102F2**) is still in effect. Other than as disclosed herein, no current director or executive officer or securityholder holding a sufficient number of securities of PET or Administrator to affect materially the control of PET or the Administrator has, within the last ten years prior to the date of this document:
been a director, chief executive officer or chief financial officer of any company (including the Administrator) that was subject to an order while the director or executive officer was acting in the capacity as director, chief executive officer or chief financial officer, or been subject to an order that was issued after the director or executive officer ceased to be a director, chief executive officer or chief financial officer and which resulted from an event that occurred while that person was acting in the capacity as director, chief executive officer or chief financial officer;

been a director or executive officer of any company (including the Administrator) that, while such person was acting in that capacity, or within a year of that person ceasing to act in that capacity, became bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency or was subject to or instituted any proceedings, arrangement for compromise with creditors or had a receiver, receiver manager or trustee appointed to hold its assets; or

become bankrupt, made a proposal under any legislation relating to bankruptcy or insolvency, or become subject to or instituted any proceedings, arrangement or compromise with creditors, or had a receiver, receiver manager or trustee appointed to hold the assets of the director, officer or securityholder.

Additionally, other than disclosed herein, no current director or executive officer or securityholder holding a sufficient number of securities of PET or the Administrator to affect materially the control of PET or the Administrator has been subject to: (i) any penalties or sanctions imposed by a court relating to securities legislation or by a securities regulatory authority or has entered into a settlement agreement with a securities regulatory authority; or (ii) any other penalties or sanctions imposed by a court or regulatory body that would likely be considered important to a reasonable investor in making an investment decision.

**Conflicts of Interest**

There may be situations in which the interests of the Administrator's management will conflict with those of the Unitholders. Certain members of management may own oil and natural gas properties that do not form part of the properties held by POT. Certain members of management may also acquire interests in energy-related businesses for their own account and on behalf of persons other than the Unitholders.

Generally, management will carry on our activities on behalf of the Unitholders. At times, however, certain members of management or certain directors may act in contradiction to or in competition with the interests of the Unitholders when acting on behalf of other industry participants. Potential conflict of interest situations are required to be disclosed in accordance with our Code of Business Conduct. The Administrator has executed indemnity agreements with each of the directors and officers of the Administrator containing terms and conditions as are standard in such agreements.

In resolving conflicts, management will deal fairly and in good faith with all interested parties. The Administrator's Board of Directors will require the facts and substance of any particular conflict be fully disclosed and will use all reasonable efforts to resolve conflicts in a manner that will treat PET or POT, as the case may be, and the other interested party fairly. All of our ongoing and future affiliated transactions will be made or entered into on terms that are no less favourable to us than those that we can obtain from unaffiliated third parties. All ongoing and future affiliated transactions and any forgiveness of loans must be approved by a majority of the independent members of the Board of Directors.

We will resolve conflicts between PET and the Administrator's officers and directors, including conflicts relating to corporate opportunities, in accordance with all applicable legislation and on the advice of counsel as required. Under the ABCA, a director is required to disclose to the Board any interest in any material contract or proposed material contract with the Administrator and may be required to refrain from voting on any resolution to approve such contract. Members of the Board may serve as directors or officers of entities which compete with us. We cannot assure that such Board members will make us aware of opportunities they identify.

As at March 9, 2010, we are not aware of any existing or potential material conflicts of interest between the Trust or the Administrator or a subsidiary thereof and a director or officer of the Administrator or of a subsidiary of the Trust or Administrator. (See "**RISK FACTORS**"**)**.

## AUDIT COMMITTEE INFORMATION

### Audit Committee Charter

The mandate and responsibilities of our audit committee (the "**Audit Committee**") are set out in the Audit Committee Charter which is part of our Corporate Governance Directors' Manual. The Audit Committee Charter is set out in Appendix "E" to this annual information form, which Appendix is incorporated in this annual information form by reference.

### Audit Committee

The Audit Committee reviews and recommends to the Board the approval of the annual and interim financial statements, the associated management's discussion and analysis and related financial disclosure to the public and regulatory authorities. It is responsible for the engagement of our external auditors, upon approval by Unitholders, including fees paid for the annual audit and interim financial reviews, and pre-approves non-audit services. The committee communicates directly with the auditors and reviews programs and policies regarding the effectiveness of internal controls over our accounting and financial reporting systems. It also reviews insurance coverage and directors' and officers' liability insurance. The Audit Committee must liaise with the Reserves Committee on matters relating to reserves valuations which impact our financial statements.

### Composition of the Audit Committee

The Audit Committee consists of three members: Robert A. Maitland, John W. (Jack) Peltier and Randall E. Johnson. Mr. Maitland is Chair of the Audit Committee. Each of the members of the Audit Committee is independent and financially literate in accordance with the meanings set out in National Instrument 52-110 *Audit Committees*.

### Relevant Education and Experience

***Robert A. Maitland***

Mr. Maitland is a Chartered Accountant and has completed the Institute of Corporate Directors - Director Education Program. He has over 30 years of senior business experience, primarily in the oil and gas industry and has been the Vice President and Chief Financial Officer of Summit Resources Ltd., Omega Hydrocarbons Ltd., Shiningbank Energy Income Fund, Post Energy Ltd., Pan East Petroleum Corp., Fairborne Energy Ltd. and Fairquest Energy Ltd. He presently serves on the board of directors of the Developmental Disabilities Resources Centre and several other private companies.

***John W. (Jack) Peltier***

Mr. Peltier graduated from the Royal Military College of Canada with a Bachelor of Science degree and Queen's University at Kingston with an M.B.A. Mr. Peltier received his Chartered Financial Analyst designation in 1974 and is a member of the CFA Institute. Since 1978 he has been President of Ipperwash Resources Ltd. and predecessor companies, a private company providing management and financial consulting services. From March 2001 he was a trustee and then Chairman of the Board of Trustees of Request Income Trust until its acquisition by Pulse Data Inc. in January 2002. From 1986 to June 2001 he was a member and then Chairman of the board of directors of Enermark Inc. and concurrently of the Board of Trustees of Enermark Income Fund. From May 2000 to June 2001 he was a member of the board of directors of Enerplus Resources Corporation, and concurrently a member of the Board of Trustees of Enerplus Resources Fund. The aforementioned entities merged to continue as Enerplus Resources Fund in June 2001. From July 1995 to October 1996 he was the Chief Financial Officer of Bow Valley Energy Ltd. where he was a director from 1996 to February 2002 and rejoined the board as a director on May 18, 2005. He has been a director of Masters Energy Inc since October 2004, a Trustee of Gienow Windows and Doors Income Fund since October 2004 and Ember Resources Inc. since July, 2005. In the past 5 years Mr. Peltier has also been a director on the board of the following public entities in addition to those described above: Thunder Energy Inc. from October 1995 to July 2005 when it was reorganized into Thunder Energy Trust (and then a trustee of Thunder Energy Trust until April 2006); Courage Energy Inc. (November 2000 to July 2001); and Manhattan Resources Ltd. (October 2001 to January 2003).

***Randall E. Johnson***

Mr. Johnson graduated with a Bachelor of Science degree in Mathematics (1980) and a Masters of Business Administration degree (1982) from Brigham Young University in Provo, Utah. His 22 year career in Corporate Banking commenced with CIBC in 1982 in Calgary. In 1984, he moved to Bank of Montreal's Corporate Banking group where worked as an Associate from 1984 to 1987, Account Manager from 1987 to 1990, Director from 1990 to 1996, and then as Managing Director from 1996 to 2005. After retiring from Bank of Montreal in January 2005, Mr. Johnson joined the Board of Directors of three publicly traded oil and gas companies: Atlas Energy Ltd. (May 2005 to December 2006), Dual Exploration Inc. (June 2005 to November 2006), and PET (June 2006 to present). During 2005 and 2006, Mr. Johnson was a part-time faculty member of the Bisset School of Business at Mount Royal College.

**Pre-Approval of Policies and Procedures**

We have adopted policies and procedures with respect to the pre-approval of audit and permitted non-audit services to be provided by KPMG LLP. The Audit Committee establishes a budget for the provision of a specified list of audit and permitted non-audit services that the audit committee believes to be typical, recurring or otherwise likely to be provided by KPMG LLP. The budget generally covers the period between the adoption of the budget and the next meeting of the Audit Committee, but at the option of the Audit Committee it may cover a longer or shorter period. The list of services is sufficiently detailed as to the particular services to be provided to ensure that (i) the Audit Committee knows precisely what services it is being asked to pre-approve and (ii) it is not necessary for any member of management to make a judgment as to whether a proposed service fits within the pre-approved services.

The Audit Committee must pre-approve the provision of permitted services by KPMG LLP which are not otherwise pre-approved by the Audit Committee, including the fees and terms of the proposed services. Prohibited services may not be pre-approved by the Audit Committee.

**External Auditor Service Fees**

***Audit Fees***

The aggregate fees billed by our external auditor in each of the last two fiscal years for audit services were $636,315, in 2009 and $536,000 in 2008, which includes fees for the Trust's year-end audit and quarterly reviews.

***Audit-Related Fees***

The aggregate fees billed in each of the last two fiscal years for assurance related services by our external auditor that are reasonably related to the performance of the audit or review of the financial statements that are not reported under ***Audit Fees*** above were $83,450 in 2009 and $5,000 in 2008. Fees for 2009 were primarily related to the takeover bid circular for the Profound acquisition. In both 2008 and 2009, we incurred fees for the filing of the Trust's form 40-F in the United States.

***Tax Fees***

The aggregate fees billed in each of the last two fiscal years for professional services rendered by our external auditor for tax compliance, tax advice and tax planning were $38,124 in 2009 and $12,305 in 2008.

These services relate to the determination and reporting of taxability of security distributions for each of Canada and the United States, the preparation and filing of Canadian trust and corporate income tax returns, and services with respect to discussions on tax compliance in various foreign jurisdictions.

***All Other Fees***

The aggregate fees billed in the 2009 fiscal year by our external auditor for services other than those services reported above were $22,000, and were related to the Trust's transition to International Financial Reporting Standards. No fees were billed in 2008.

## PREMIUM DISTRIBUTION™ AND DISTRIBUTION REINVESTMENT PLAN

PET announced on September 21, 2009 that it has adopted a Premium Distribution™ component in its Distribution Reinvestment Plan (the "Premium DRIP") in connection with the September 2009 cash distribution. The Premium Drip supersedes, amends and restates in its entirety the Distribution Reinvestment and Optional Trust Unit Purchase Plan of PET dated December 17, 2003 (the "Original Plan"). The primary differences between the Premium DRIP and the Original Plan are the addition of the Premium Distribution™ component under the Premium DRIP and the discontinuation of the optional Trust Unit purchase component which was available under the Original Plan.

The Premium DRIP allows eligible Unitholders to elect, under the distribution reinvestment component of the Premium DRIP, to have their monthly cash distributions reinvested in additional Trust Units on the applicable distribution payment date. Participants in the distribution reinvestment component of the Premium DRIP will have the ability, as was the case with the Original Plan, to purchase Trust Units with distribution proceeds at a price per Trust Unit equal to 94 percent of the Average Market Price (as defined in the Premium DRIP). The Premium DRIP also allows eligible Unitholders to otherwise elect, under the Premium Distribution™ component of the Premium DRIP, to have these additional Trust Units delivered to the designated Plan Broker in exchange for a premium cash payment equal to 102% of the cash distribution such Unitholders would otherwise have received on the applicable distribution payment date. In the event that eligible Unitholders elect to participate in the Premium Distribution™ component of the Premium DRIP, the additional Trust Units delivered to the designated Plan Broker will be issued from treasury at a five percent discount to the Average Market Price. Canaccord Capital Corporation will act as the Plan Broker for the Premium Distribution™ component of the Premium DRIP.

No commissions, service charges or brokerage fees are payable in connection with the purchase of Trust Units from PET under either component of the Premium DRIP. All administrative costs of the Premium DRIP will be paid by PET. Unitholders who wish to participate in the Premium DRIP indirectly through the brokers, investment dealers, financial institutions or other similar nominees through which their Trust Units are held should consult such nominees to confirm whether commissions, service charges or other fees are payable.

## LEGAL PROCEEDINGS AND REGULATORY ACTIONS

There are no material legal proceedings to which we are a party or in respect of which any of our properties are subject, nor are there any such proceedings known to be contemplated.

No penalties or sanctions were imposed in 2009 against the Trust or its subsidiaries by a court relating to securities legislation or by a securities regulatory authority, and nor were any other penalties or sanctions imposed by a court or regulatory body against the Trust or its subsidiaries that would likely be considered important to a reasonable investor in making an investment decision. Additionally, no settlement agreements were entered into in 2009 by the Trust or its subsidiaries before a court relating to securities legislation or with a securities regulatory authority.

## INTEREST OF MANAGEMENT AND OTHERS IN MATERIAL TRANSACTIONS

There were no material interests, direct or indirect, of the Administrator's directors and senior officers, any Unitholder who beneficially owns more than 10 percent of the outstanding Trust Units, or any known associate or affiliate of such persons, in any transaction within the three most recently completed financial years or during the current financial year that has materially affected or is reasonably likely to materially affect PET other than (i) certain insiders purchasing common shares of Severo Energy Corp. In 2006 by way of private placement and (ii) as disclosed herin.

## AUDITORS, TRANSFER AGENT AND REGISTRAR

Our auditors are KPMG LLP, Chartered Accountants, Calgary, Alberta.

Computershare Trust Company of Canada at its offices in Calgary, Alberta and Toronto, Ontario acts as the transfer agent and registrar for the Trust Units and Debenture Trustee for the Convertible Debentures.

## MATERIAL CONTRACTS

Except for contracts we entered into in the ordinary course of business or otherwise disclosed in this annual information form, the only material contracts outstanding are the following:

the Trust Indenture;
the POT Indenture;
the POT Royalty Agreement;
the 6.25% Convertible Debenture Trust Indenture;
the 6.50% Convertible Debenture Trust Indenture; and
the 7.25% Convertible Debenture Trust Indenture.

These documents can be found on SEDAR at www.sedar.com.

## INTEREST OF EXPERTS

### Names of Experts

The only persons or companies who are named as having prepared or certified a statement, report or valuation described or included in a filing, or referred to in a filing, made under National Instrument 51-102 by the Trust during, or relating to, the Trust's most recently completed financial year, and whose profession or business gives authority to the statement, report or valuation made by the person or company, are KPMG LLP, the Trust's independent auditors, McDaniel, the Trust's independent engineering evaluators and Prevent, the Trust's independent asset retirement obligation evaluators.

### Interests of Experts

To the Administrator's knowledge, no registered or beneficial interests, direct or indirect, in any securities or other property of the Trust or of one of the Trust's associates or affiliates (i) were held by McDaniel or Prevent when McDaniel or Prevent prepared the statement, report or valuation in question, (ii) were received by McDaniel or Prevent after McDaniel or Prevent prepared the statement, report or valuation in question, or (iii) is to be received by McDaniel or Prevent.
Neither KPMG LLP, McDaniel or Prevent, nor any director, officer or employee of KPMG LLP, McDaniel or Prevent, is or is expected to be elected, appointed or employed as a director, officer or employee of the Administrator or of any associate or affiliate of the Administrator.

KPMG LLP is independent within the meaning of the Rules of Professional Conduct of the Institute of Chartered Accountants of Alberta.

## GOVERNMENT REGULATION

Various levels of government impose extensive controls and regulations on the oil and natural gas industry. Some of the more significant aspects are outlined below.

### Regulatory Compliance Governed by ERCB

The ERCB regulates the development of Alberta's natural energy resources. We are subject to, and are in material compliance with regulations, rulings and other requirements administered by the ERCB.

The most significant regulatory impact on us has been from the ERCB's decisions and orders related to the shut-in of natural gas in favour of bitumen conversation. See **REGULATORY RULINGS – GAS OVER BITUMEN**.

### The North American Free Trade Agreement

We are bound by the energy terms of the North American Free Trade Agreement ("NAFTA"), among the governments of Canada, the U.S. and Mexico. Canada is able to restrict exports or energy resources if the export restrictions do not: (i) reduce the proportion of energy resources exported relative to the total supply of the energy resource (based upon the proportion prevailing in the most recent 36 month period), (ii) impose an export price higher than the domestic price, or (iii) disrupt normal channels of supply. All three countries are prohibited from imposing minimum export or import price requirements. NAFTA contemplates the reduction of Mexican restrictive trade practices in the energy sector and prohibits discriminatory border restrictions and export taxes. NAFTA contemplates a fair implementation of regulatory changes and minimal disruption of contractual arrangements.

### Land Tenure

The governments of the western provinces own most of the crude oil and natural gas located in such provinces. These provincial governments grant rights to explore for and produce oil and natural gas for varying terms and on conditions set forth in legislation. Oil and natural gas located in such provinces can also be privately owned (freehold). Freehold rights owners may grant rights to explore for and produce oil and natural gas on negotiated terms.

### Royalties and Incentives

In addition to federal regulations, each province has legislation and regulations which govern land tenure, royalties, production rates, environmental protection and other matters. The royalty regime is a significant factor in the profitability of oil and natural gas production. Negotiations between a freehold mineral owner and the lessee determine royalties' payable on production from lands other than Crown lands. Government regulation determines Crown royalties which are generally calculated as a percentage of the gross production. The rate of Crown royalties payable depends in part on the prescribed reference prices (which represent the average prices for sale of specific commodities), well productivity, geographical location, field discovery date, the method of recovery and the type or quality of the petroleum product. The governments of Canada and Alberta have established incentive programs including royalty rate reductions, royalty holidays and tax credits for the purpose of encouraging oil and natural gas exploration or enhanced production projects.

From time to time the governments of the Western Canadian provinces create incentive programs for exploration and development. Such programs often provide for royalty rate reductions, royalty holidays and tax credits, and are generally introduced when commodity prices are low. The programs are designed to encourage exploration and development activity by improved earnings and funds flow within the industry.

The Government of Alberta receives royalties on production of natural resources from lands in which it owns the mineral rights. On October 25, 2007, the Government of Alberta announced a new royalty regime. The new regime will introduce

new royalties for conventional oil, natural gas, oil sands and bitumen effective January 1, 2009 that are linked to price and production levels and applies to both new and existing oil sands production.
The new royalty formula for conventional oil production on Crown lands in Alberta operates on a sliding rate formula containing separate elements that account for oil price and monthly well production. Royalty rates for conventional oil will range up to 50 percent, with rate caps once the price of conventional oil reaches $120 per barrel.

Under the new Alberta regime, natural gas royalties are set by a sliding rate formula sensitive to price and production volume. New natural gas royalty rates range from five to 50 percent with rate caps once the price of natural gas reaches $16.59/GJ. Royalties for natural gas liquids will be set at 40 percent for pentanes and 30 percent for butanes and propane. (See **"History and Development – *Recent Developments***)

## ADDITIONAL INFORMATION

Additional information, including directors' and officers' remuneration and indebtedness, principal holders of our securities and securities authorized for issuance under our equity compensation plans, is contained in our management information and proxy circular for the most recent annual meeting of shareholders that involved the election of directors. Additional financial information is provided in our consolidated financial statements and management's discussion and analysis for the year ended December 31, 2009. Documents affecting the rights of securityholders, along with additional information relating to PET, can be found on SEDAR at www.sedar.com.

## APPENDIX A

## THE POT ROYALTY AGREEMENT

**Grant of Royalty**

Under the POT Royalty Agreement, POT granted the POT Royalty to us with respect to all petroleum and natural gas properties POT may acquire and hold from time to time. Pursuant to the POT Royalty, we are entitled to receive 99 percent of POT's net revenue from its petroleum and natural gas properties, less permitted deductions with respect to debt payments, capital expenditures and certain other amounts.

The POT Royalty does not constitute an interest in land. We generally are not entitled to take our share of production in kind or to separately sell or market our share of petroleum substances produced from POT's petroleum and natural gas properties, but can do so subject to certain conditions in the case of POT's insolvency.

**Payment of Royalty Income**

The royalty income POT pays to us pursuant to the POT Royalty Agreement with respect to a particular payment period will be paid in cash on the 15th day (or the next business day if the 15th is not a business day) of the following month. The POT Royalty Agreement allows the board of directors to elect payment periods and they have determined to make distributions on a monthly basis. The POT Royalty Agreement obligates POT to pay all Crown charges in respect of its petroleum and natural gas properties. We are required to reimburse POT for 99 percent of such charges that, prior to 2003, were not deductible for income tax purposes. At POT's option, such reimbursement may be set-off against amounts POT is obliged to pay us under the POT Royalty Agreement.

**Deferred Purchase Price Obligation**

The POT Royalty attaches to all petroleum and natural gas properties POT acquires from time to time. In recognition of this feature of the POT Royalty, the POT Royalty Agreement requires us to make certain royalty purchase payments in addition to the payment made upon the grant of the POT Royalty ("**Deferred Royalty Purchase Payments**") and are generally required in three circumstances. First, when POT acquires petroleum or natural gas properties, we must pay POT as a Deferred Royalty Purchase Payment 99 percent of the intangible cost of such properties that is not financed with indebtedness POT incurs or assumes. Second, when we raise equity by way of issuing Trust Units, POT may require us to make a Deferred Royalty Purchase Payment of up to the lesser of the net proceeds of that issuance and 99 percent of POT's debt that reasonably relates to petroleum or natural gas properties previously acquired or in respect of which POT has incurred capital expenditures for which we have not already paid a Deferred Royalty Purchase Payment. Third, POT may require us to fund, as a Deferred Royalty Purchase Payment, 99 percent of capital expenditures that POT proposes to incur in respect of the intangible costs associated with petroleum or natural gas properties, to the extent such expenditures are not financed with indebtedness.

As a result of the Deferred Royalty Purchase Payments and loans that we will from time to time make to POT, we will provide POT with 99 percent of the funding it requires to acquire petroleum and natural gas properties. POT will bear the remaining 1 percent of the cost of such properties and the entire cost of tangible equipment relating to any such properties utilizing its own working capital or funds it borrows for such purposes.

**Acquisition of Properties**

The POT Royalty Agreement permits POT to acquire petroleum or natural gas properties that have a reserve value that is 20 percent or less of the reserve value of all of POT's petroleum and natural gas properties without approval of the Administrator's board of directors. Acquisitions in excess of this amount must be approved by the board. The board may add to or change the foregoing restrictions on the acquisition of such properties.

**Disposition of Properties**

The POT Royalty Agreement permits POT to sell tangible and other properties related to its petroleum and natural gas properties and to license geological or other data it has rights to, so long as it acts reasonably and in accordance with prudent oil and gas industry practice. Generally, these properties will not be subject to the POT Royalty.

The POT Royalty Agreement permits POT to dispose of petroleum and natural gas properties that are subject to the POT Royalty and requires us to release the POT Royalty with respect to such dispositions provided that three conditions are met: (a) POT is of the reasonable opinion that such sale is in our best interest; (b) if the sale is comprised of assets having a reserve value of 20 percent or more of the reserve value of all of POT's petroleum and natural gas properties, the board of directors has approved the sale; and (c) if the sale is comprised of assets having a reserve value of 50 percent or more of the reserve value of all of POT's petroleum and natural gas properties, Unitholders have approved the sale by Special Resolution. Notwithstanding the foregoing, the POT Royalty Agreement provides that if our lenders act upon their security, they may dispose of POT's petroleum and natural gas properties and the associated POT Royalty without obtaining the approvals referred to above.

If POT sells any petroleum or natural gas rights, 99 percent of the net proceeds of the sale will, subject to the following, be allocated to us with respect to the POT Royalty, and 1 percent will be allocated to POT. POT will hold the proceeds of disposition allocated to us in trust and may pay such funds to us, set such funds off against any Deferred Royalty Purchase Payment we owe to POT or use such funds to acquire additional properties or maintain and develop existing properties.

**Term of POT Royalty Agreement**

The POT Royalty Agreement will continue in force for so long as POT owns any properties that are subject to such agreement, or holds any proceeds of disposition in trust for PET.

**Credit Facilities**

POT is authorized to borrow funds and grant security both with respect to its own borrowing and with respect to certain third party obligations it may from time to time guarantee, such as our debts, for the purpose of obtaining the credit necessary to acquire, develop and operate its properties.

## THE TRUST INDENTURE

The following information summarizes the material information contained in the Trust Indenture. The Trust Indenture provides for the governance of the Trust. While this summary discusses all material information, it is not exhaustive and may not contain all of the information that is important to you.

**General**

We were established for the purposes of issuing Trust Units and acquiring and holding royalties and other investments including the entire beneficial interest in POT and the POT Royalty.

Subject to the provisions of applicable law, the Trust Indenture contains an acknowledgement that the directors and officers of the Administrator may be engaged directly or indirectly in the oil and gas industry and gas advisory and consulting businesses in Canada and elsewhere. Nothing in the Trust Indenture prohibits such persons from undertaking such engagements. The Trust Indenture specifies that the Administrator will require any such person to disclose to the Trustee any conflict of the interests of such persons with the interests of the Trust within a reasonable period of time after such person ascertains such conflict.

Canadian securities legislation puts reporting obligations on persons who acquire more than a certain percentage of our securities. Generally, no obligations are triggered until a threshold of 10 percent or more of the outstanding class of securities is acquired. The provisions dealing with reporting obligations are complex and persons approaching this threshold should consult with their professional advisors. There are also constraints on non-Canadian ownership of our securities. (See "**DESCRIPTION OF CAPITAL STRUCTURE Constraints for Non-Resident Unitholders")**.

**Investment Powers**

Under the Trust Indenture, we have broad powers to invest funds not distributed to Unitholders, including the power:

- to fund POT or any subsidiary of ours to enable them to further develop their oil and natural gas assets or to acquire, directly or indirectly, further producing assets and facilities of any kind related thereto; and
- to make any other investments of any kind or nature including loan advances to, and acquiring shares and/or beneficial interests in, other entities,

provided that the Administrator has covenanted to use reasonable commercial efforts to ensure that we do not acquire any investment which:

- is defined as "foreign property" under any provision of the *Income Tax Act* (Canada) if such acquisition would cause the Trust Units to be foreign property under the *Income Tax Act* (Canada); or
- would result in our not being considered either a "unit trust" or a "mutual fund trust" for purposes of the *Income Tax Act* (Canada) at the time such investment was acquired.

**Meetings and Resolutions of Unitholders**

Meetings of Unitholders will be called at least annually. By a resolution approved at a meeting of Unitholders by more than 50 percent of the votes cast ("**Ordinary Resolution**") Unitholders will vote on, among other things:

- the appointment of the Trustee;
- the appointment or removal of our auditors; and
- the election or removal of the Administrator's directors.

A Special Resolution is necessary for, among other things:

- removal of the Trustee;
- amending the Trust Indenture except as described under **Amendments to the Trust Indenture**;
- subdivision or consolidation of the Trust Units unless otherwise provided for in the Trust Indenture (see **DESCRIPTION OF CAPITAL STRUCTURE Distributions**);
- sale of all or substantially all of our assets other than:
  - (i) a sale to an entity wholly-owned, directly or indirectly, by us; or
  - (ii) a sale pursuant to any enforcement or realization proceedings by any person that has been granted a security interest over all or part of our assets;
- assignment, transfer or sale of any royalty payable by any entity to us, including the POT Royalty ("**Royalty**") in whole or in part other than:
  - (i) a sale to an entity wholly-owned, directly or indirectly;
  - (ii) a sale made in conjunction with the sale of the corresponding interest in the oil and gas properties of POT to which such Royalty relates, subject to necessary approvals of the board of directors and Unitholders, if any, under that Royalty; or
  - (iii) a sale made pursuant to or in connection with any enforcement or realization proceedings of lenders to us or to POT upon security interests granted to them;
- termination or winding-up of our affairs; and
- appointment of an inspector to investigate the Trustee's performance.

Meetings of Unitholders shall be held in the City of Calgary or at such other place as the Trustee designates. In addition to annual meetings, the Trustee may require further meetings. Unitholders holding not less than five percent of the outstanding Trust Units or the Administrator may requisition a meeting.

Unitholders may attend and vote at all meetings of Unitholders either in person or by proxy and a proxyholder need not be a Unitholder. A quorum for any meeting shall be two or more persons, present in person or represented by proxy, holding in the aggregate not less than five percent of the votes attaching to all outstanding Trust Units. We will include holders of Special Voting Units for the purposes of calculating a quorum.

**The Trustee**

The Trust Indenture appoints Computershare Trust Company of Canada as our initial trustee. The Trustee may exercise all rights, powers and privileges that could be exercised by a beneficial owner of our assets.

The Trustee shall be reappointed or changed at every annual meeting of Unitholders and will continue to hold the office of Trustee until the Unitholders appoint a successor.

The Trustee may resign from the office on giving not less than 60 days' notice in writing. The Trustee may be removed by notice in writing delivered by the Administrator to the Trustee at any time the Trustee no longer satisfies the financial or other qualification requirements under the Trust Indenture. Such resignation or removal becomes effective upon the acceptance or appointment of a successor trustee. The Trustee, the Administrator or any Unitholder may make application to a court with appropriate jurisdiction to appoint a successor trustee if one has not been put in place within certain time periods as detailed in the Trust Indenture.

The Administrator will pay the Trustee fees and reimburse the Trustee for reasonable expenses it incurs in connection with our administration. The Trustee shall have a lien on our assets with priority over the interests of the Unitholders to enforce payment of its fees and these expenses.

**Delegation of Authority, Administration and Trust Governance**

The Trustee may grant or delegate to the Administrator or other persons such power and authority as the Trustee may deem necessary or desirable to perform any of the duties of the Trustee. The Trustee has effectively delegated to the Administrator all significant management, administrative and governance functions pertaining to the Trust, including matters related to:

- any sale or surrender of any Royalty;
- any demand under, or sale or surrender, of any debt instruments;
- any sale or surrender of any interest that we hold in POT or in any other entity it controls, directly or indirectly;
- any acquisition or disposition of permitted investments;
- any offering of securities;
- any terms and any amendment to certain material agreements of ours;
- any underwriting agreement;
- any exercise of rights, powers and privileges relating to a response to an offer for Trust Units or for all or substantially all of our assets, or of any its subsidiaries;
- any redemption of Trust Units;
- credit facilities, borrowings, hedging, security for indebtedness (including guarantees) or other agreement to facilitate our borrowing;
- any financial statements and tax filings;
- any compliance with our legal or listing obligations;
- any calculation of distributions; and
- any meetings of Unitholders.

The Administrator may further delegate the powers and authorities that the Trustee delegated to it under the terms of the Trust Indenture.

The Trustee cannot delegate the following rights, duties and obligations:

- without limiting the duties and obligations of the Transfer Agent, the countersigning, transferring and cancelling of certificates representing Trust Units and the maintenance of registers of Unitholders;
- the payment and delivery of distributions to Unitholders;
- amending the provisions of the Trust Indenture other than making changes or corrections that legal counsel to the Trustee advises are necessary or desirable and are not materially adverse to the interests of the Unitholders or the Administrator;
- waiving the performance or breach of the provisions of the Trust Indenture;
- terminating the Trust Indenture and certain material agreements of ours; and
- indemnifying the Administrator, any entity we control directly or indirectly, and the directors, officers, employees and agents of those entities in connection with services they perform for us or the Trustee.

**Limitations on Liability of the Trustee and the Administrator**

The Trustee, the Administrator and their respective directors, officers, employees and agents shall not be liable to any Unitholder (in its capacity as such), in tort, contract or otherwise, in connection with any matter pertaining to us including, without limitation:

- any error in judgment;
- any action taken or suffered or omitted to be taken in good faith in reliance on either any document that is *prima facie* properly executed or any Ordinary Resolution or Special Resolution;
- any dealing with any asset that resulted in the depreciation of or loss to PET;
- any reliance on any evaluation or assessment provided by an appropriately qualified person;
- any reliance in good faith on any communication from the Administrator to the Trustee or from the Trustee to the Administrator as to any matter, fact or opinion; and
- any other action or failure to act.

The Trustee, the Administrator and any of their respective directors, officers, employees or agents remain liable for their own gross negligence, wilful misconduct or fraud. The Trust Indenture provides that, in addition to any other indemnity provided by contract or at law, the Trustee, each of its directors, officers, employees and agents and each of their respective heirs, executors, successors and assigns (collectively in this paragraph, the "**Indemnified Parties**") are to be indemnified out of our assets in respect of all liabilities, losses, costs, charges, damages, penalties and expenses (collectively in this paragraph, the "**Liabilities**") suffered or incurred in respect of any claims or proceedings that are proposed or commenced against any Indemnified Party in respect of acting as or on our behalf or the Trustee, any act, omission or error in respect of the Trust or the carrying out of any Trustee's duties or responsibilities under the Trust Indenture (including any such Liabilities relating to environmental matters and issues). However, such indemnification will not be applicable to an Indemnified Party to the extent that any of such Liabilities is suffered or incurred as a result of the Indemnified Party's own gross negligence, wilful misconduct or fraud.

The Trustee and its directors, officers, employees and agents have a lien on our assets to enforce payment of the indemnification provided to them. This lien has priority over the interests of Unitholders. The Administrator has a lien to enforce payment of the indemnification provided to it. This lien has priority over the interests of the Unitholders but will be subordinated and postponed to any security interests granted to our lenders. The indemnities to the directors, officers, employees and agents of the Administrator are unsecured obligations and do not constitute a lien on our assets. The Trustee may, however, grant a security interest in our assets to secure any such indemnity obligation to any such person if that person delivers a subordination and postponement satisfactory to our lenders.

The Trust Indenture provides that, in the exercise of the powers provided to it, the Trustee will be deemed to be acting as trustee of our assets and will not be subject to any personal liability for any liabilities or obligations against or with respect to the Trust or its assets. The Trustee will have no liability for any matters delegated to, or actions taken by, the Administrator.

The Trust Indenture does not hold the Administrator or any of its directors, officers, employees or agents or respective successors to the standard of a trustee in respect of matters delegated to the Administrator. The Trust Indenture provides that, in addition to any other indemnity provided by contract or at law, the Administrator, each of its directors, officers, employees and agents and each of their respective heirs, executors, successors and assigns (collectively in this paragraph, the "**Indemnified Parties**") are to be indemnified out of our assets in respect of all liabilities, losses, costs, charges, damages, penalties and expenses (collectively in this paragraph, the "**Liabilities**") suffered or incurred in respect of any claims or proceedings that are proposed or commenced against any Indemnified Party in respect of acting or not acting in connection with matters delegated to the Administrator, any act, omission or error in respect of the Trust or the carrying out of any of the matters delegated to the Administrator under the Trust Indenture (including any such Liabilities relating to environmental matters and issues). However, such indemnification will not be applicable to an Indemnified Party to the extent that any of such Liabilities is suffered or incurred as a result of the Indemnified Party's own gross negligence, wilful misconduct or fraud.

The Trust Indenture provides that none of the Unitholders, PET or the Trustee, in their respective capacities, shall have any right of action against the Administrator or any of the directors, officers, employees or agents of the Administrator or any of their respective heirs, executors, successors and assigns, for acts of the Administrator or any of the directors, officers, employees or agents of the Administrator, where such action is based on any allegation that the Administrator or any director, officer, employee or agent of the Administrator was a trustee for, or acting in a fiduciary capacity (or any other basis similar thereto) with respect to, the Unitholders, PET or the Trustee, in their respective capacities as such, in respect of matters delegated to the Administrator under the Trust Indenture.

The Trust Indenture provides that the Administrator will have no liability for any matters delegated by it to third persons for the actions of those third persons. The Administrator will be entitled to the indemnities provided to it in respect of that delegation and actions provided the Administrator has monitored the performance of the third party in accordance with the appropriate standard of care.

**Expenses of the Administrator**

We will reimburse the Administrator for reasonable expenditures and costs the Administrator incurs in our management and administration. This reimbursement is not intended to provide the Administrator, directly or indirectly, with any financial gain or loss. The Administrator has agreed that such reimbursement will be only to the extent necessary to reimburse the Administrator for actual costs incurred, including any costs of capital in respect of carrying any such costs, together with any goods and services taxes applicable thereto, until reimbursement. The Administrator has a lien on our assets to enforce payment of the costs and expenses and other amounts we must pay or reimburse to the Administrator. The Administrator's lien has priority over the interests of Unitholders, but is subordinated and postponed to any security interests granted to any lender.

**Amendments to the Trust Indenture**

The Trustee may amend any of the provisions of the Trust Indenture at any time, without the consent, approval or ratification of any of the Unitholders or any other person, for the purpose of:

- ensuring that we will comply with any applicable laws or requirements of any governmental agency or authority of Canada or of any province;
- ensuring that we will satisfy the provisions of each of subsections 108(2) and 132(6) of the *Income Tax Act* (Canada) as from time to time amended or replaced;
- ensuring that such additional protection is provided for the interests of Unitholders as the Trustee may consider expedient;
- removing or curing any conflicts or inconsistencies between the provisions of the Trust Indenture or certain material agreements of ours, or any applicable law or regulation of any jurisdiction, provided that in the opinion of the Trustee the rights of the Trustee, the Administrator and of the Unitholders are not prejudiced thereby;

- making changes for any other purpose not inconsistent with the terms of the Trust Indenture and agreements relating to any Royalty, including curing, correcting or rectifying any ambiguities, defective or inconsistent provisions, errors, mistakes or omissions, provided that in the opinion of the Trustee, the rights of the Trustee, the Administrator and of the Unitholders are not prejudiced thereby; and
- providing for the electronic delivery to the Unitholders, including Special Unitholders, of documents relating to the Trust (including annual and quarterly reports and financial statements and proxy-related materials) in accordance with applicable law from time to time.

**Take-over Bids**

The Trust Indenture provides that if an offeror makes a take-over bid for the Trust Units and acquires 90 percent or more of the Trust Units (other than Trust Units held at the date of the takeover bid by or on behalf of the offeror or associates or affiliates of the offeror) the offeror may acquire the Trust Units of Unitholders who did not accept the take-over bid, without the consent or approval of such Unitholders, on the offeror's terms under the take-over bid.

**Termination of PET**

PET will terminate on December 31, 2102. The Unitholders may vote by Special Resolution to terminate PET at an earlier date only if:

- holders of not less than 20 percent of the issued and outstanding Trust Units request in writing that PET be terminated and a quorum constituted by the holders of not less than 50 percent of the issued and outstanding Trust Units is present in person or by proxy at the meeting at which the Special Resolution is adopted; or
- the Trust Units have become ineligible for investment by Canadian registered retirement savings plans, registered retirement income funds, registered education savings plans and deferred profit sharing plans.

Upon the Unitholders' vote to terminate PET, the Trustee shall commence to wind-up our affairs. The Trustee will sell and convert into money, or otherwise dispose of, the Royalties and other assets in accordance with the directions, if any, of the Unitholders and the Administrator. We will not be wound-up until the Trustee has disposed of all Royalties and other investments.

The Trustee will liquidate all of our assets, satisfy or provide for our obligations and then distribute any remaining proceeds to Unitholders. Unitholders must tender their banknote form of certificates representing their Trust Units to receive their share of the proceeds. We will terminate when the Trustee has disposed of all of our assets and satisfied or provided for all of our obligations. In no event is the winding-up of our affairs to exceed ten years.

**Auditors**

Our auditors must be an independent recognized firm of chartered accountants with an office in Calgary, Alberta. KPMG LLP, Chartered Accountants, are presently the auditors and will hold office until the next annual meeting of Unitholders. Unitholders will appoint auditors at each successive annual meeting. The Trustee, with the approval of the Unitholders, may remove the auditors and appoint new auditors.

**Reporting to Unitholders**

We are subject to the continuous disclosure obligations under applicable securities legislation including the obligation to file quarterly and annual financial reports. Our year-end is December 31.

## THE POT INDENTURE

The following information summarizes the material information contained in the POT Indenture.

**Power and Authority of the Administrator as trustee of POT**

The POT Indenture provides the Administrator, as trustee of POT, with the widest possible latitude and discretion in carrying out its rights and duties as trustee of POT, including, the power and capacity to:

- sell, transfer, assign and convey all or any part of POT's property;
- retain any investments in real or personal property which come into its possession as trustee;
- invest and reinvest any property coming into its hands as trustee in its sole discretion without being limited by any statute covering investments by trustees;
- vote any securities;
- act our absolute representative in respect of matters pertaining to the administration of the assets of POT;
- invest POT's property and assets in investments of every nature;
- borrow money from or lend money to any person on such terms and conditions as the Administrator considers appropriate;
- assume debt, and pledge, mortgage or otherwise encumber POT's properties;
- guarantee, indemnify or act as a surety or become jointly and severally liable with respect to the payment or performance of any indebtedness, liabilities or obligations of any person (including the beneficiary of POT, being PET) and to pledge, mortgage or otherwise encumber POT's properties (including all legal and beneficial interests therein) in respect of those guarantees, indemnities, suretyships or liabilities;
- join, directly or indirectly, in any syndicate, partnership or joint venture contributing all or part of the properties of POT as the contribution of POT thereto;
- explore, develop, purchase, hold, operate, market and divest petroleum, hydrocarbons, crude bitumen, oil sands, natural gas, coal bed methane, natural gas liquids, related hydrocarbons and any and all other substances producible in association therewith and related facilities and other miscellaneous interests;
- institute, prosecute, and defend any suit, action, arbitration proceeding or other proceeding affecting the Administrator or POT's properties;
- engage in rate swap transactions and derivatives for hedging purposes; and
  employ and pay any other person or persons to transact any business or to do any act of any nature in relation to POT's assets and properties.

The Administrator may resign as POT's trustee on giving not less than 30 days' written notice to us. We may remove the Administrator as trustee only on provision of a full release from liability for the Administrator and its directors, officers, employees and agents in respect of the administration of POT, except in respect of gross negligence, fraud or wilful misconduct. In addition, the Administrator shall cease to act as POT's trustee if it:

- enters into a liquidation, whether compulsory or voluntary, except a voluntary liquidation for the purpose of amalgamation or reconstruction;
- is found not to have the capacity to act as a trustee or is found to be in breach of applicable legislation governing the activities of bodies corporate as trustees; or
  is declared bankrupt or insolvent.

The Administrator is entitled to charge POT for all expenses the Administrator reasonably incurs in carrying out its duties as trustee. The Administrator will allocate such expenses and other amounts as income or capital on POT assets as it sees fit.

**POT Beneficiary and PET Unitholder Limited Liability**

The POT Indenture provides that no beneficiary of POT (being PET) nor any of the beneficiaries of the beneficiary (the Unitholders), in their capacity as such, will incur or be subject to any liability in connection with the assets of POT or the obligations or the affairs of POT, including acts or omissions of the Administrator. In addition, the beneficiary of POT (being PET) and its beneficiaries (being the Unitholders), in their respective capacities as such, are not contractually liable to indemnify any person for any of the above liabilities, including taxes any person may incur on behalf of POT. If, however, a court assesses any of such liabilities against us, as beneficiary of POT, or any of the Unitholders, then those liabilities will be enforceable only against and be satisfied only out of the assets of POT. POT will indemnify us, as beneficiary of POT, and the Unitholders, to the extent of POT's assets, from liability arising as a result of PET or the Unitholders not having such limited liability.

Every written contract POT enters into, unless otherwise agreed to by the Administrator, must include a provision substantially to the effect that the obligations thereunder will not be personally binding upon the Administrator, or POT's beneficiary (being PET), including its own beneficiaries, the Unitholders, in their respective capacities as such.

**Notwithstanding the terms of the POT Indenture and the Trust Indenture, the beneficiary of POT (being PET) and the Unitholders, in their capacities as such, may not be protected from liabilities of POT to the same extent a shareholder is protected from the liabilities of a corporation. Personal liability may also arise in respect of claims against POT (to the extent that POT does not satisfy claims) including contract claims, tort claims, environmental claims, claims for taxes and certain other statutory liabilities. Unlike many other royalty trusts and income funds our structure does not include the interposition of a limited liability entity such as a corporation or limited partnership which would provide further limited liability protection to Unitholders.**

Note, however, that on July 1, 2004 the *Income Trust Liability Act* (Alberta) came into force creating a statutory limitation on the liability of Unitholders of Alberta income trusts such as the Trust. The legislation provides that a Unitholder will not be, as a beneficiary, liable for any act, default, obligation or liability of the trustee. The implementation of the *Income Trust Liability Act* (Alberta) assists in mitigating the effect of the Trust's structure and its lack of an inter-positioned limited liability entity for claims after July 1, 2004. This legislation has not been subject to interpretation by courts in the Province of Alberta.

We will conduct POT's business so as to avoid as far as reasonably possible any material risk of liability to POT's beneficiary (being PET) and the Unitholders, in their respective capacities as such. We intend to obtain insurance where available and appropriate for the operations of POT and the Administrator, however, the amounts and types of insurance obtained may not be sufficient to provide full coverage.

**Distributions of POT**

POT is required to distribute all of its income for tax purposes each year to us. If any such distribution or a part thereof is contrary to any credit facility of POT, the Administrator may include in the distribution a demand subordinated, unsecured promissory note with a face amount equal to the amount of the distribution not permitted to be delivered to us. Such notes will be subordinated and postponed to liabilities to lenders of POT and to our lenders whose obligations have been guaranteed by POT.

**Approval Requirements of Beneficiary**

The POT Indenture provides that POT's beneficiary (PET) must approve certain matters including:

- the sale of any assets of POT to the Administrator;
- the amendment of any terms of the POT Indenture;
- certain matters relating to the Administrator; and
- the termination of POT.

**Limitations of Liability of the Administrator**

The POT Indenture provides the Administrator, in its capacity as POT's trustee, with similar limitations on its liability to us, as are provided in the Trust Indenture to the Administrator in connection with the powers and authorities delegated to it in the Trust Indenture. The Administrator, as trustee of POT, is also provided with indemnities similar to that provided in the Trust Indenture to the Administrator in connection with the powers and authorities delegated to it in the Trust Indenture. The POT Indenture provides that the indemnities provided under the POT Indenture are all unsecured claims and do not constitute a lien on the assets of POT. (See "**THE TRUST INDENTURE -Limitations on Liability of the Trustee and the Administrator"** in Appendix "**A**")
Prohibited Amendments to POT Indenture

The POT Indenture prohibits amendments that result in any of the following:

- a change to a discretionary power of any mandatory duty imposed on the Administrator as trustee, unless the Administrator consents; or
- distributions of income or capital of POT among the beneficiaries of POT other than in accordance with the pro rata share of each such beneficiary, unless they otherwise consent.

## APPENDIX B

## REPORT OF MANAGEMENT AND DIRECTORS ON Oil AND GAS DISCLOSURE IN ACCORDANCE WITH FORM 51-101F3

Management of Paramount Energy Operating Corp., as Trustee of Paramount Operating Trust ("POT") and Administrator of Paramount Energy Trust ("PET") (collectively "PET" or "the Trust") are responsible for the preparation and disclosure of information with respect to PET's oil and gas activities in accordance with securities regulatory requirements. This information includes reserves data, which are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

McDaniel & Associates Consultants Ltd. ("**McDaniel**"), an independent qualified reserves evaluator, has evaluated PET's Reserves Data. The report of McDaniel is presented below.

The Reserves Committee of the board of directors of Paramount Energy Operating Corp., as Trustee of POT and Administrator of PET ("**Board**" or "**Board of Directors**") has:

(a) reviewed the PET's procedures for providing information to McDaniel;
(b) met with McDaniel to determine whether any restrictions affected the ability of McDaniel to report without reservation and to inquire whether there had been any disputes between McDaniel and management; and
(c) reviewed the reserves data with management and McDaniel.

The Reserves Committee of the Board of Directors has reviewed PET's procedures for assembling and reporting other information associated with oil and gas activities and has reviewed that information with management. The Board has, on the recommendation of the Reserves Committee, approved:

(a) the content and filing with securities regulatory authorities of Form 51-101F1 containing reserves data and other oil and gas information;
(b) the filing of Form 51-101F2 which is the report of McDaniel on the reserves data; and
(c) the content and filing of this report.

Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

/s/ Susan L. Riddell Rose
Susan L. Riddell Rose
President and Chief Executive Officer

/s/ Cameron R. Sebastian
Cameron R. Sebastian
Vice President, Finance and Chief Financial Officer

/s/ Robert A. Maitland
Robert A. Maitland
Director, Chairman of the Audit Committee

/s/ Donald J. Nelson
Donald J. Nelson
Director, Chairman of the Reserves Committee

March 9, 2010

## APPENDIX C

## REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD. IN ACCORDANCE WITH FORM 51-101F2

McDaniel & ASSOCIATES CONSULTANTS LTD. Oil & Gas Reservoir Evaluations

February 9, 2010

**Paramount Energy Trust**
3200, 605 – 5th Avenue S.W.
Calgary, Alberta
T2P 3H5

Attention: The Board of Directors of Paramount Energy Trust

Re: **Form 51-101F2**
**Report on Reserves Data by an Independent Qualified Reserves Evaluator of Paramount Energy Trust (the "Company")**

**To the Board of Directors of Paramount Energy Trust (the "Company"):**

1. We have evaluated the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenues as at December 31, 2009 estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2009, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

**Net Present Value of Future Net Revenue ($thousands)**
**(before income taxes, 10% discount rate)**

| Preparation Date of Evaluation Report | Location of Reserves | Audited | Evaluated | Reviewed | Total |
|---|---|---|---|---|---|
| February 2, 2010 | Canada | - | 1,091,971 | - | 1,091,971 |

5. In our opinion, the reserves data respectively evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

**MCDANIEL & ASSOCIATES CONSULTANTS LTD.**

"signed by P.A Welch"

P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta

Suite 2200, Bow Valley Square 3, 255-5th Avenue S.W., Calgary, Alberta T2P 3G6
Tel: (403) 262-5506 Fax: (403) 233-2744 Email: mcdaniel@mcdan.com Website: www.mcdan.com

## APPENDIX D

## REPORT ON RESERVES DATA BY MCDANIEL & ASSOCIATES CONSULTANTS LTD. IN ACCORDANCE WITH FORM 51-101F2

McDaniel & ASSOCIATES CONSULTANTS LTD. Oil & Gas Reservoir Evaluations

February 9, 2010

**Severo Energy Corp.**
3200, 605 – 5th Avenue S.W.
Calgary, Alberta
T2P 3H5

Attention: The Board of Directors of Severo Energy Corp.

Re: **Form 51-101F2**
**Report on Reserves Data by an Independent Qualified Reserves Evaluator**
**of Severo Energy Corp. (the "Company")**

**To the Board of Directors of Severo Energy Corp. (the "Company"):**

1. We have evaluated the Company's reserves data as at December 31, 2009. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2009, estimated using forecast prices and costs.

2. The reserves data are the responsibility of the Company's management. Our responsibility is to express an opinion on the reserves data based on our evaluation.

   We carried out our evaluation in accordance with standards set out in the Canadian Oil and Gas Evaluation Handbook (the "COGE Handbook") prepared jointly by the Society of Petroleum Evaluation Engineers (Calgary Chapter) and the Canadian Institute of Mining, Metallurgy & Petroleum (Petroleum Society).

3. Those standards require that we plan and perform an evaluation to obtain reasonable assurance as to whether the reserves data are free of material misstatement. An evaluation also includes assessing whether the reserves data are in accordance with principles and definitions presented in the COGE Handbook.

4. The following table sets forth the estimated future net revenue (before deduction of income taxes) attributed to proved plus probable reserves, estimated using forecast prices and costs and calculated using a discount rate of 10 percent, included in the reserves data of the Company evaluated by us, for the year ended December 31, 2009, and identifies the respective portions thereof that we have evaluated and reported on to the Company's management:

**Net Present Value of Future Net Revenue ($thousands)**
**(before income taxes, 10% discount rate)**

| Preparation Date of Evaluation Report | Location of Reserves | Audited | Evaluated | Reviewed | Total |
|---|---|---|---|---|---|
| February 2, 2010 | Canada | - | 17,641 | - | 17,641 |

5. In our opinion, the reserves data evaluated by us have, in all material respects, been determined and are in accordance with the COGE Handbook. We express no opinion on the reserves data that we reviewed but did not audit or evaluate.

6. We have no responsibility to update our report referred to in paragraph 4 for events and circumstances occurring after the preparation date.

7. Because the reserves data are based on judgments regarding future events, actual results will vary and the variations may be material. However, any variations should be consistent with the fact that reserves are categorized according to the probability of their recovery.

Executed as to our report referred to above:

**MCDANIEL & ASSOCIATES CONSULTANTS LTD.**

“signed by P.A. Welch”

P. A. Welch, P. Eng.
President & Managing Director

Calgary, Alberta

## APPENDIX E

## AUDIT COMMITTEE CHARTER

The Audit Committee is responsible for:

- reviewing and, if appropriate, recommending to the Board the approval of the annual and interim financial statements, the associated MD&A and related financial disclosure;
- annually reviewing the Audit Committee mandate and recommending any changes to the Corporate Governance Committee;
- supplying for the purposes of this Manual, in consultation with Corporate Counsel, a list of the laws, rules and regulations that pertain to the operation of the Committee;
- engaging external Auditors as approved by PET's Unitholders;
- pre-approving non-audit permitted services including the fees and other terms related to the non-audit permitted services;
- communicating directly with the Auditors who will report directly to the Audit Committee;
- reviewing programs and policies regarding the maintenance and effectiveness of disclosure controls and internal controls over the Trust's accounting and financial reporting systems;
- reviewing insurance coverage and Directors' and Officers' liability insurance; and,
- liaising with the reserves committee ("Reserves Committee") on matters relating to reserves valuations which impact the financial statements of PET.

**Purpose**

The Audit Committee's purpose is to provide assistance to the Board in fulfilling its legal, regulatory and fiduciary obligations with respect to: financial accounting, internal control processes, continuous public disclosure, the independent audit function, non-audit services provided by Independent Auditors and such other related matters as may be delegated by the Board of Directors.

**Composition, Procedures and Organization**

1. The Audit Committee will be comprised of three or more Directors as determined from time to time by resolution of the Board.
2. Each member of the Audit Committee must be independent (defined on page 3-4) and as such must be free from any material relationship that may interfere with the exercise of his or her independent judgment as a member of the Audit Committee.
3. Consistent with the appointment of other Board committees, the members of the Audit Committee will be appointed by the Board at the first meeting of the Board following each AGM or at such other time as may be determined by the Board.
4. The Committee will designate the Chairman of the Audit Committee by majority vote. The presence in person or by telephone of a majority of the Audit Committee's members constitutes a quorum for any meeting.
5. All actions of the Audit Committee will require a vote of the majority of its members present at a meeting of such committee at which a quorum is present.
6. All members of the Audit Committee must be financially literate at the time of their appointment or have become financially literate within a reasonable period of time after such appointment. MI 52-110 sets out that an individual is "financially literate" if he or she has the ability to read and understand a set of financial statements that present a breadth and level of complexity of accounting issues that are generally comparable to the breadth and complexity of the issues that can reasonably be expected to be raised by PET's financial statements.
7. The Board shall designate at least one Audit Committee member as the financial expert, and the member so designated must have accounting or related financial management expertise, as such qualification may be determined in the business judgment of the Board in accordance with the requirements of applicable regulatory bodies.

**Accountability and Reporting**

The Audit Committee is accountable to the Board. The Audit Committee must provide the Board with a summary of all meetings and its recommendations together with a copy of the minutes of each such meeting. If applicable, the Chairman will provide oral reports as requested.
All information reviewed and discussed by the Audit Committee at any meeting must be retained and made available for examination by the Board. The Audit Committee will review its mandate annually, and will forward to the Corporate Governance Committee any recommended alterations to that mandate.

**Meetings**

The Committee will meet with such frequency and at such intervals as it determines is necessary to carry out its duties and responsibilities.

The Audit Committee will meet to review the interim and year-end financial statements and MD&A; related financial public disclosure and regulatory filings including the annual information form, management information circular; other continuous disclosure documentation ("Continuous Disclosure Documents") as described in MI 52-101 (which is incorporated herein by reference); the Auditor's Report with respect to annual attestation of Internal Controls over Financial Reporting ("ICOFR"), and to report to the Board on same. In conjunction with the review of the year-end financial statements and MD&A, the Audit Committee will consider the annual independent evaluation of the oil and gas reserves of PET. In addition to these scheduled quarterly meetings as contained in "Planning Documents For Board and Committees" (Section 4 of the Manual), the Audit Committee may meet on other occasions with the Auditors in order to be advised of current practices in the industry and to discuss and review other matters including the annual work plans, processes and procedures. The Audit Committee must meet at least quarterly with the Auditors in the absence of PET's Officers and employees to discuss any matters that the Committee or a committee member believes should be discussed privately.

The Chairman of the Audit Committee will appoint a Director, Officer or employee of PET to act as secretary for the purposes of recording the minutes of each meeting.

**Responsibilities**

The Audit Committee must:

- review and approve the Audit Committee Mandate annually;
- review and recommend to the Board the appointment, termination and retention of, and the compensation to be paid to, the Auditors;
- evaluate the performance of the Auditors;
- review and consider the Auditors' integrated audit plan and annual engagement letter including the proposed fees and the proposed work plan;
- consider and make recommendations to the Board or otherwise pre-approve, all non-audit services provided by the Auditors to PET or its subsidiaries;
- oversee the work and the performance of the Auditors, review the independence of the Auditors and report to the Board on these matters;
- review the annual and quarterly financial statements, MD&A and financial press releases, annual information form, Management Information Circular and other related Continuous Disclosure Documents as appropriate, prior to their public disclosure;
- oversee management's establishment and maintenance of ICOFR to provide reasonable assurance with regard to reliability of financial reporting;
- review the Auditors' report on the annual audited financial statements and related assessment of ICOFR and the Auditor's review letters on interim financial statements;

- provide oral or written reports to the Board when necessary;
- resolve disagreements between management and the Auditors regarding financial reporting;
- receive periodic certificates and reports from management with respect to compliance with financial, regulatory, taxation and continuous disclosure requirements, and satisfy itself (a) that adequate procedures are in place to ensure timely and full public disclosure of Continuous Disclosure Documents; and, (b) that a system of internal controls over financial reporting has been implemented and is being maintained, in accordance with both the Disclosure Policy and the Management Responsibility For Internal Control Policy; and additionally, must consider whether any identified deficiencies in internal controls are significant or are material weaknesses;
- meet with the Auditors, without management being present, at each time the interim and financial statements are being considered, to ensure that no management restrictions have been placed on the scope of the Auditors' work and to discuss the working relationship between the Auditors and management and other matters that the Audit Committee or the Auditors may wish to raise;
- review and monitor the implementation and adequacy of disclosure policies;
- review insurance coverage including Directors' and Officers' liability insurance;
- be notified in writing within three business days of any embezzlement, litigation or regulatory investigation which, in the opinion of the Trust's management, is objectively significant. Confirmation of receipt of such notification by each member of the Audit Committee will additionally be required. Any embezzlement, litigation or regulatory investigation not reported as outlined above will be reported quarterly to the Board of Directors at the March, May, August, and November meetings immediately following the discovery of such occurrence;
- review and monitor the implementation and adequacy of hedging policies and controls, with reference to the Trust's Hedging and Risk Management Policy, which is attached to this Manual in Section 7;
- review compliance with applicable laws, regulations and policies;
- be advised of and review the results of any internal audits of PET and report on same to the Board;
- establish a Whistle blower Policy with procedures for:

(a) the receipt, retention and treatment of complaints received by PET regarding accounting, internal accounting controls, or auditing matters; and
(b) the confidential, anonymous submission by employees of the issuer of concerns regarding questionable accounting or auditing matters;

- ensure that PET management regularly advises employees of the existence of a Whistleblower Process;
- receive regular reports respecting complaints made under the Whistleblower Process;
- inform the Auditors of whether the Audit Committee has knowledge of any actual, suspected or alleged fraud affecting PET, including complaints regarding financial reporting and confidential submissions by employees;
- review and validate PET management's annual review of fraud risk assessment;
- review and approve PET's hiring policies regarding partners, employees and former partners and employees of the present and former Auditor of the issuer; and
- monitor the selection and application of proper accounting principles and practices and to review the status of all relevant financial and related fiduciary aspects of PET.