PARAMOUNT
ENERGY TRUST

ANNUAL INFORMATION FORM

FOR THE YEAR ENDED DECEMBER 31, 2008

DATED: **March 10, 2009**

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ABBREVIATIONS

Natural Gas	
Mcf	thousand cubic feet
MMcf	million cubic feet
Bcf	billion cubic feet
Mcf/d	thousand cubic feet per day
MMcf/d	million cubic feet per day
m^3	cubic metres
MMbtu	million British Thermal Units
GJ	gigajoule

Oil and Liquids	
Bbl	barrels
Mbbl	thousand barrels
Bpd	barrels per day
m^3	cubic metres

Approximately 99 percent of PET's annual production volumes and 98 percent of PET's proved and 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, 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 STATEMENTS

Certain statements contained in the annual information form constitute forward-looking statements. These statements relate to future events or to our future performance. All statements other than statements of historical fact may be forward-looking statements. Forward-looking statements are often, but not always, identified by the use of the words "anticipate", "plan", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "predict", "targeting", "seek", "intend", "could", "potential", "should" and similar expressions. These 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 statements. We believe the expectations reflected in those forward-looking statements are reasonable but no assurance can be given that these expectations will prove to be correct. Such forward-looking statements included in the annual information form should not be unduly relied upon. These statements speak only as of the date of the annual information form. In particular, the annual information form contains forward-looking statements pertaining to the following:

- the size of our natural gas reserves;
- estimates of future funds flow and distributions;
- projections of market prices and costs and the related sensitivities to distributions;
- natural gas production levels;
- capital expenditure programs;
- supply and demand for natural gas;
- expectations regarding the ability to raise capital and to continually add to reserves through acquisitions, exploration and development; and
- treatment under governmental regulatory regimes, both existing and proposed.

The actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set out below and elsewhere in the annual information form:

- volatility in market prices for natural gas;
- liabilities inherent in natural gas operations;
- adverse regulatory rulings, orders and decisions;
- uncertainties associated with estimating natural gas reserves;
- competition for, among other things, capital, acquisitions of reserves and undeveloped lands, service providers and skilled personnel;
- incorrect assessments of reserves and the value of acquisitions;
- geological, technical, drilling and processing problems; and
- the other factors discussed under **RISK FACTORS.**

With respect to forward-looking statements contained in this Annual Information Form, we have made assumptions regarding: current commodity prices and royalty regimes; availability of skilled labour; north American sulphur prices; timing and amount of capital expenditures; future exchange rates; the price of oil and natural gas; the impact of increasing competition; conditions in general economic and financial markets; availability of drilling and related equipment; effects of regulation by governmental agencies; royalty rates and future operating costs.

Management has included the above summary of assumptions and risks related to forward-looking information provided in this Annual Information Form in order to provide Unitholders (as defined herein) with a more complete perspective on our future operations and such information may not be appropriate for other purposes. Actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits we will derive there from. Readers are cautioned that the foregoing lists of factors are not exhaustive.

Statements relating to “reserves” or “resources” are deemed to be forward-looking statements as they involve the implied assessment, based on certain estimates and assumptions that the resources and reserves described can be profitably produced in the future. Readers are cautioned that the foregoing lists of factors are not exhaustive. The forward looking statements contained in this annual information form are expressly qualified by this cautionary statement. None of PET, the Administrator nor POT (each defined below) undertakes any obligation to publicly update or revise any forward-looking statements unless expressly required to do so by applicable securities laws. Further, readers should also carefully consider the matters discussed under the heading **RISK FACTORS** in this annual information form.

NON-GAAP MEASURES

In this annual information form, we use funds flow from operations before changes in non-cash working capital (**"funds flow"**) and funds flow per Trust Unit to analyze operating performance and financial 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. Funds flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow from operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Funds flow cannot be assured and future distributions may vary. All references to "funds flow" are based on funds flow before changes in non-cash working capital related to operating activities, certain exploration costs and settlement of asset retirement obligations. 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.

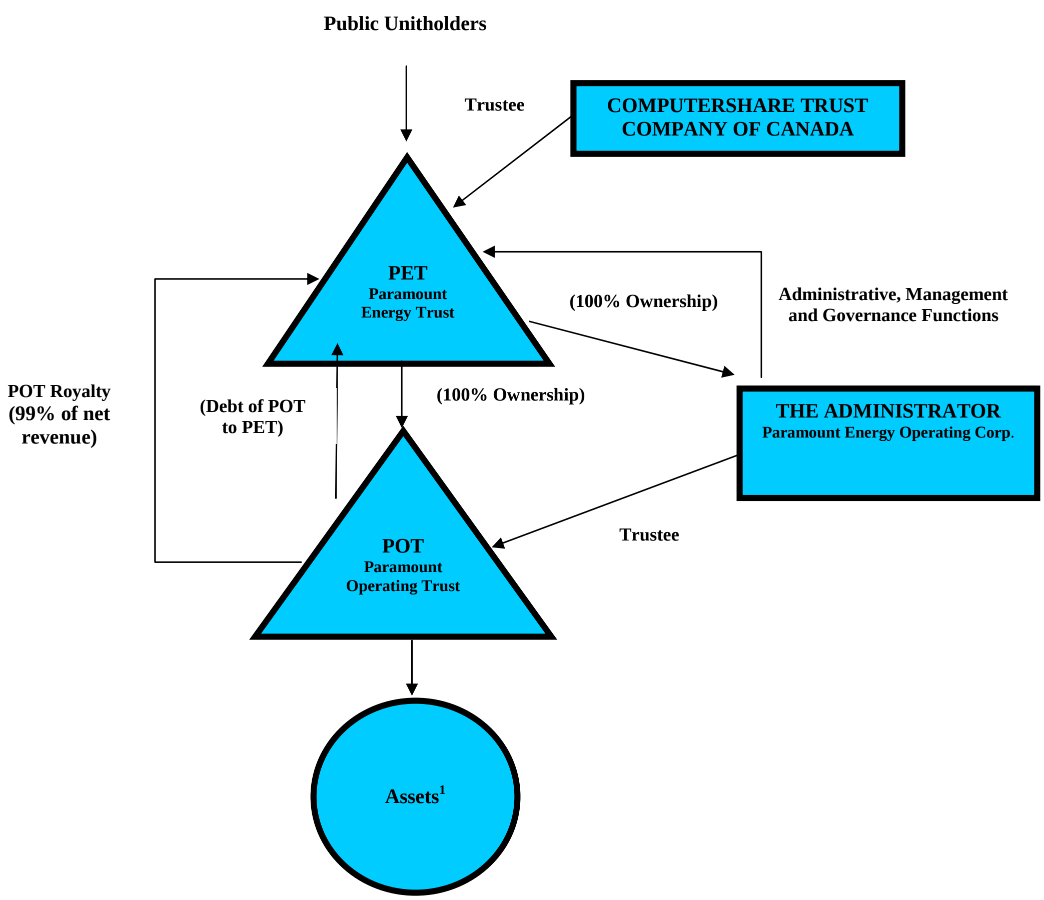
We were established for the purposes of issuing trust units ("**Trust Units**") and acquiring and holding royalties and other investments including the entire beneficial interest in POT and the POT Royalty (defined below). We effectively finance the operations of POT. We make cash distributions to holders 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:

(1) Our assets are directly held by POT and several corporations and partnerships. POT is PET's only principal subsidiary, holding total assets that exceed 10 percent of our total consolidated assets or revenues as at and for the year ended December 31, 2008.

GENERAL DEVELOPMENT OF THE BUSINESS

Formation of the Trust

In April and May of 2002, the board of directors of Paramount Resources Ltd. ("**PRL**") gave its initial approval to the formation and structuring of a trust to hold a number of mature producing properties of PRL. Pursuant to the proposal, PRL would distribute the units of such trust to the holders of its common shares ("**PRL Common Shares**") through a dividend-in-kind. The mature, net cash generating, producing properties to be transferred to the trust were considered to be suitable for a trust and management of PRL believed the transaction would be financially beneficial to shareholders of PRL. In January of 2003, the board of directors of PRL gave its final approval to the transaction and to the final Canadian prospectus and U.S. registration statement of PET which were prepared to facilitate the transaction. The following transactions were completed on February 3, 2003:

- POT acquired PRL's natural gas properties and facilities in the Legend, Alberta area (the "**Initial Assets**") in exchange for the issuance by POT to PRL of an $81 million promissory note. POT assumed all risks on these assets and revenues and expenses associated with these assets accrued to POT for POT's account, effective July 1, 2002;
- PRL and POT entered into a purchase and sale agreement under which POT agreed to acquire from PRL up to 100 percent of PRL's interests in most of its remaining natural gas properties in northeast Alberta (the "**Additional Assets**"); and
- POT entered into the POT Royalty Agreement with PET effective July 1, 2002. As a result of a number of steps completed in connection with the payment of the consideration for the POT Royalty, PET issued 9,909,766 Trust Units to PRL and acquired the remaining $16,848,000 in indebtedness that POT owed to PRL.

The board of directors of PRL declared and, on February 12, 2003, paid a dividend-in-kind to the holders of PRL Common Shares of all of the Trust Units PRL received pursuant to the above transactions on the basis of one Trust Unit for each 6.071646 PRL Common Share held as of February 11, 2003.

The Trust Units commenced trading on the TSX on a when-issued basis on February 7, 2003.

On February 15, 2003, we issued to our Unitholders three transferable rights (referred to in this part as "**Rights**"), qualified by our prospectus dated January 29, 2003 for every Trust Unit held of record on February 14, 2003. Each Right entitled the holder to acquire one Trust Unit for a price of $5.05 until March 10, 2003. All of the Trust Units offered under this Rights offering were subscribed for. As a result, on March 11, 2003 PET issued an aggregate of 29,728,609 Trust Units pursuant to the exercise of the Rights and received net aggregate subscription proceeds of $150.1 million.

On March 11, 2003, we utilized the Rights subscription proceeds and the proceeds of bank financing arranged by us to repay $30.1 million owing to PRL and to acquire from PRL 100 percent of PRL's interest in the natural gas assets and facilities provided for in the purchase and sale agreement referred to above for a cash purchase price of $220 million. POT assumed all risks on these assets and revenues and expenses associated with these assets accrued to POT for POT's account, effective July 1, 2002. These acquisitions from PRL constituted a "significant acquisition" as that term is defined under applicable Canadian securities legislation.

History and Development

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

Year Ended December 31, 2006

<u>East Central Alberta Acquisition</u>

In February 2006, PET completed the acquisition of a private Alberta company for $92 million, adding operated, shallow gas production in east central Alberta. The acquisition also provided the Trust with 60,700 net acres of year-round access undeveloped land in east central Alberta and over 50 defined prospects which meet PET's risk profile.

Convertible Debenture Financing

PET completed an issue on March 30, 2006 by way of short form prospectus of $100,000,000 aggregate principal amounts of 6.25% convertible extendible unsecured subordinated debentures (the "**2006 6.25% Convertible Debentures**") with a conversion price of $23.80 per Trust Unit.

Internal Restructuring

In the third quarter of 2006, PET completed an internal restructuring in order to facilitate the development of certain assets south of its Athabasca core area. Assets producing approximately 1.4 MMcf/d were transferred to a private company, Severo Energy Corp. ("**Severo**"), which is 93 percent indirectly owned by PET.

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. PET has filed on SEDAR a Form 51-102F4 Business Acquisition Report in respect of this acquisition.

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 "**2007 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 and RESP accounts.

In June 2008 the federal government proposed amendments to the trust tax regulation ("Provincial SIFT Tax Amendments") so that, instead of basing the provincial component of the tax on a flat tax rate of 13 percent, the provincial component would be instead based on the general provincial corporate income tax rate in each province in which PET has a permanent establishment. On July 14, 2008 the Department of Finance released draft legislation which prescribed the provincial allocation formula to be applied with respect to the Provincial SIFT tax. Specifically, PET's taxable distributions will be allocated to provinces by taking half of the aggregate of:

(a) that proportion of the Trust's taxable distributions for the year that the Trust's wages and salaries in the province are of its total wages and salaries in Canada; and
(b) that proportion of the Trust's taxable distributions for the year that the Trust's gross revenues in the province are of its total gross revenues in Canada.

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. These regulations are not yet considered substantively enacted for accounting purposes at December 31, 2008 therefore the provincial component of the Trust Tax Legislation is 13 percent 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 shut-in deemed production, as well as 5.0 Bcfe of proved and probable reserves.

Recent Developments

On October 25, 2007, the Government of Alberta announced a “New Royalty Framework” for oil and natural gas royalties in the Province of Alberta. New royalty rates apply to all production effective January 1, 2009. At the McDaniel price forecast of $7.00 per GJ at AECO in 2009 and assuming production of the recognized reserves only, the royalty rate for PET’s production in 2009 is expected to be virtually equal to what it would have been under the previous royalty regime. PET’s assessment is that, based on the Trust’s current profile of well productivity and at various natural gas prices, the effect of the new royalty framework on cash flow will be approximately as shown below. Royalty rates will rise relative to their pre-2009 levels at higher gas prices, and decrease relative to their pre-2009 levels at lower gas prices.

	AECO gas price ($/GJ)				
Estimated change in royalty rate (1)	**$5.00**	**$6.00**	**$7.00**	**$8.00**	**$10.00**
Estimated crown royalty rate in 2009 under pre-2009 royalties	17.0%	17.0%	17.0%	17.0%	17.0%
Estimated crown royalty rate in 2009 under current royalties	5.8%	10.3%	14.8%	17.8%	23.8%
Increase (decrease) in royalty rate [percentage points]	-11.2%	-6.7%	-2.2%	0.8%	6.8%
Percentage increase (decrease) in royalty rate [%]	-65.8%	-39.3%	-12.9%	4.8%	40.1%

(1) PET estimated average 2009 well productivity based on McDaniel Report is 167 Mcf/d.

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. The program is effective 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 for the next year 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, 2010.

PET is current evaluating the potential impact of these incentives on 2009 capital programs.

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 pursuing multiple new venture opportunities synergistic with our Northeast and East Central Alberta shallow gas 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

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

The Trust's asset base is comprised of properties in seven core areas: West Side; East Side; Athabasca (all in northeast Alberta); Birchwavy East; Birchwavy West; East Central Alberta (all in east central and southern Alberta); and assets owned by Severo (in central Alberta). In addition, PET has certain other minor assets in southern Alberta as well as southwest Saskatchewan. Most fields are characterized by long production histories and gas wells have demonstrated a predictable decline in production as reserves have been 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 cash 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 out 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 continue to target the acquisition of high quality assets with substantial low risk development potential and low capital requirements. We will not limit our acquisitions by commodity or geography although we intend to continue our focus on natural gas assets and our focus in our northeast and east central Alberta operating areas. 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. As of the date of the annual information form, we have not reached agreement on the price or terms of any potential future acquisition. 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.

Environment, Health and Safety (EH&S)

Safety is our number one priority at PET. Our core values of accountability and integrity support our strong commitment to both compliance with applicable legislation, and achievement of high standards of workplace health and safety and environmental stewardship throughout all phases of our operations.

At PET our commitment to excellence is achieved through consistent and integrated processes between head office and the field. In addition to formal policies, procedures and training programs, we foster individual responsibility and support creativity through an open exchange of ideas with our field personnel. Continual improvements are achieved through performance monitoring, root cause and failure analyses and subsequent corrective action plans. Open communication, reinforced with bonus incentives and safety recognition awards for field staff emphasize operational improvements that are practical and effective. Our people understand that environmental stewardship and the highest standards of safety go hand in hand with sound business decisions.

Our EH&S programs are guided by a committee of the board of directors with the majority being non-management directors. This committee provides directives for safety and environmental policies to protect the environment, maintain the health and safety of our employees, service providers and the public, and ensure compliance with all applicable laws, regulations and standards.

PET incorporates continuous improvement into our business planning and operations. Our operations are aligned with industry best practices and we strive to meet or exceed all regulatory requirements. PET believes that its interest, and those of its stakeholders and the communities in which it operates, are best served by proactively managing its environmental affairs. Our business is run by people and like our neighbours we share the land with; we want to maintain a certain quality of life and do the right things for the environment, as an active participation with Alberta Environment in the “Partners in Resources Program”. PET participates in many industry tracking and benchmarking initiatives, both mandatory and voluntary, including Fugitive Emissions Leak Detection and Repair, Air Quality Assurance Plans, the National Pollutant Release Inventory, the Canadian Greenhouse Gas Challenge Registry, the Carbon Disclosure Project, the Canadian Association of Petroleum Producers Stewardship Benchmarking Initiative, federal and provincial greenhouse gas reporting initiatives. PET meets all reporting requirements as mandated by regulatory authorities. In the event of an emergency, formal response programs are designed to minimize environmental and safety impacts. Finally, internal audit of our management systems and operations provides for continuous improvement to all aspects of EH&S.

Business Conditions

Industry Competition

We participate in the petroleum and natural gas industry which 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.

Employees

As of December 31, 2008 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.

Corporate Citizenship

PET is committed to being a corporate partner in the communities in which we work. Through our In Stride With Community program, we direct funds to organizations that reflect PET's values and those of our employees and business partners. Specifically we support initiatives focused on wellness and education in its broadest context. The life priorities of our employees, consultants, service providers, business partners and our Unitholders channel our support. Our people are actively improving the quality of life for friends and neighbours in their communities. We believe their enthusiasm and passion impacts our success, and when we contribute to enhance the impact of that energy in the community, great triumphs are attained.

Environmental Protection

The oil and natural gas industry is currently subject to environmental regulations under provincial and federal legislation. Compliance with such legislation can require significant expenditures or result in operational restrictions. Breach of requirements can result in suspension or revocation of necessary licenses and authorizations, civil liability for environmental damage and the imposition of material fines and penalties. This can have a significant negative impact on earnings and overall competitiveness.

We are proactive in our approach to environmental concerns. Procedures are in place to ensure that due care is taken in the day-to-day management of our oil and gas properties. We believe that we are in material compliance with applicable environmental legislation. We pursue well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower our overall costs.

For the 2008 financial year, PET expended approximately $5.2 million for well abandonments and $0.4 million on environmental remediation and reclamation activities including certain administrative expenses related to environmental protection initiatives. PET estimates that approximately $0.7 million will be expended for environmental remediation and reclamation activities in 2009 and PET has budgeted $4.4 million for total well and facility abandonments in 2009.

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 98 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 (the "**McDaniel Reports**") by McDaniel & Associates Ltd. ("**McDaniel**") in Form 51-101F2 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 January 29, 2009. The effective date of the McDaniel Reports is December 31, 2008. 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 Paramount Energy Trust and Severo Energy Corp.

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 2014 or 2015 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 2008 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 Report.

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, 2008
FORECAST PRICES AND COSTS

RESERVES CATEGORIES	Light and Medium Crude Oil		Natural Gas		Natural Gas Liquids		Natural Gas Equivalent	
	Gross (Mbbl)	Net (Mbbl)	Gross (MMcf)	Net (MMcf)	Gross (Mbbl)	Net (Mbbl)	Gross (MMcfe)	Net (MMcfe)
Proved Producing	535	499	205,007	172,571	15	11	208,309	175,627
Proved Non-Producing	15	14	13,509	11,249	1	-	13,599	11,336
Proved Undeveloped	20	18	39,018	34,400	-	-	39,138	34,509
Total Proved	570	531	257,534	218,220	16	11	261,046	221,473
Total Probable	325	284	220,711	179,637	6	4	222,696	181,361
Proved and Probable	895	815	478,244	397,857	21	15	483,742	402,834

NET PRESENT VALUE OF FUTURE REVENUE
BEFORE TAX
as at December 31, 2008
FORECAST PRICES AND COSTS ($millions)

	BEFORE INCOME TAXES DISCOUNTED AT (%)					
RESERVES CATEGORIES	0%	5%	10%	15%	20%	UNIT VALUE BEFORE INCOME TAX DISCOUNTED AT 10%/year ($/Mcfe)
Proved Producing	1,090	916	802	719	655	3.85
Proved Non-Producing	10	14	15	14	13	1.09
Proved Undeveloped	112	81	59	43	32	1.50
Total Proved	1,213	1,011	876	776	700	3.36
Total Probable	920	631	461	346	271	2.07
Proved and Probable	2,133	1,642	1,337	1,123	971	2.76

NET PRESENT VALUE OF FUTURE REVENUE
AFTER TAX
as at December 31, 2008
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	1,019	859	755	679	620	3.62
Proved Non-Producing	9	13	14	13	12	1.00
Proved Undeveloped	82	58	41	29	20	1.04
Total Proved	1,110	930	809	720	652	3.10
Total Probable	717	489	354	268	211	1.59
Proved and Probable	1,827	1,419	1,163	989	863	2.40

**FUTURE NET REVENUE
TOTAL RESERVES (UNDISCOUNTED)
as at December 31, 2008
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	2,374	(416)	80	(612)	(92)	(123)	1,211	(100)	1,110
Proved and Probable Reserves	4,487	(787)	80	(1,170)	(327)	(151)	2,131	(304)	1,827

**FUTURE NET REVENUE
TOTAL RESERVES
BY PRODUCTION TYPE
as at December 31, 2008
FORECAST PRICES AND COSTS ($millions)**

RESERVES CATEGORY	Production Type	Future Net Revenue Before Income Taxes (discounted at 10%/year) ($millions)	Unit Value ($/Mcfe) ($/bbl)
Proved Reserves	Natural Gas and NGL	861	3.34
Proved Reserves	Oil	15	26.06
Proved Reserves - Total		876	3.36
Proved and Probable Reserves	Natural Gas and NGL	1,311	2.74
Proved and Probable Reserves	Oil	23	25.58
Proved and Probable Reserves - Total		1,334	2.76

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, 2008, 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, 2008
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)]
2009	60.00	69.60	7.40	0.85
2010	71.40	83.00	8.00	0.85
2011	83.20	91.40	8.45	0.90
2012	90.20	93.90	8.80	0.95
2013	97.40	96.30	9.05	1.00
2014	99.40	98.30	9.25	1.00
2015	101.40	100.30	9.45	1.00
2016	103.40	102.30	9.60	1.00
2017	105.40	104.20	9.80	1.00
2018	107.60	106.40	10.00	1.00
2019	109.70	108.50	10.20	1.00
2020	111.90	110.70	10.40	1.00
2021	114.10	112.80	10.60	1.00
2022	116.40	115.10	10.80	1.00
2023	118.80	117.50	11.05	1.00
Thereafter	2%	2%	2%	1.00

(1) 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, 2008 of $8.18/Mcfe for natural gas. The weighted average AECO daily gas price for the same 12 month period was $8.15/Mcfe.

Definitions and Other Notes

1. Columns and rows may not add due to rounding.

2. 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. 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;
(c) dry hole contributions and bottom hole contributions;
(d) costs of drilling and equipping exploratory wells; and
(e) 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;
(b) in relation to wells, the total number of wells in which we have an interest; and
(c) 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.
(b) in relation to wells, the number of wells obtained by aggregating our working interest in each of our gross wells; and
(c) 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.
(b) **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:

(a) at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated proved reserves; and
(b) 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

As PET's oil and natural gas liquids reserves represent less than two percent of the Trust's total reserves on a natural gas equivalent basis the following reconciliations of changes in reserves are presented on a natural gas equivalent basis.

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

FACTORS	Gross Proved	Gross Probable	Company Interest Proved And Probable
December 31, 2007 (2)	291.2	213.9	505.2
Improved Recoveries, Extensions and Discoveries(3)	21.9	18.0	39.8
Technical Revisions	10.1	(10.9)	(0.8)
Acquisitions	4.0	0.9	4.9
Dispositions	(3.7)	(1.3)	(5.0)
Production	(64.8)	-	(64.8)
Economic Factors	2.4	2.1	4.5
December 31, 2008	261.0	222.7	483.7

(1) 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**").
(2) The opening balance on December 31, 2007 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, 2007 and 2008 all reserves shut-in as a result of the gas over bitumen issue were categorized as probable reserves.
(3) The Trust includes all reserve additions resulting from capital expenditures in Extensions, Improved Recoveries and Discoveries.

RECONCILIATION OF TRUST NET RESERVES
TOTAL RESERVES (1) (2)
FORECAST PRICES AND COSTS (Bcfe)

FACTORS	Net Proved	Net Probable	Net Proved And Probable
December 31, 2007[3]	242.6	177.3	419.9
Improved Recoveries, Extensions and Discoveries[4]	18.3	14.6	32.9
Technical Revisions	13.5	(7.3)	6.3
Acquisitions (net of dispositions)	3.3	0.7	4.0
Dispositions	(3.4)	(1.2)	(4.5)
Production	(53.5)	-	(53.5)
Economic Factors	0.6	(2.8)	(2.2)
December 31, 2008	221.5	181.4	402.8

(1) 'Net' includes working interest net of all royalties payable and royalty interests.
(2) 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").**
(3) The opening balance on December 31, 2007 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, 2007 and 2008 all reserves shut-in as a result of the gas over bitumen issue were categorized as probable reserves.
(4) 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	-	-	-	-	-	-	-	-
2006	-	-	-	-	4,700	-	-	-
2007	137	20	-	-	41,070	30,859	-	-
2008	-	20	-	-	159	31,018		

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	-	-	-	-	-	-	-	-
2006	-	-	-	-	3,562	3,562	-	-
2007	35	20	-	-	90,465	87,300	-	-
2008	-	20	-	-	9,246	100,108	-	-

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%
2009	7.2	6.8	15.6	14.9
2010	16.8	14.5	43.5	37.7
2011	27.2	21.5	28.4	22.4
2012	27.5	19.7	29.0	20.7
2013	12.3	8.0	44.7	29.1
Thereafter	0.5	0.3	166.3	87.4
Total	91.5	70.8	327.5	212.3

We expect to fund future development costs from internally-generated funds flow, debt or equity financing through the capital markets or PET's Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan"), and we do not expect such costs to make development of any properties uneconomic.

The McDaniel Reports estimates that future capital costs of $327.5 million will be required over the life of PET's proved and probable reserves for the drilling, completion, equipping and tie-in of 24 conventional wells and up to 955 unconventional wells, targeting the Cretaceous Viking formation, and recompletion of up to 269 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**").

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**.**

Other Oil and Gas Information

Oil and Gas Properties

The following is a description of our oil and natural gas properties as at December 31, 2008. Production stated is our working and royalty interest share of production volumes and, unless otherwise stated, is average production for 2008. Reserve amounts stated include Trust Gross Reserves plus royalty interest reserves as at December 31, 2008 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, 2008.

Northern District

East Side

Corner/Leismer

The Corner/Leismer area is in northeast Alberta approximately 90 kilometres southwest of Fort McMurray. The area comprises 311,979 net acres (54.7 percent undeveloped) including a 97.6 percent working interest in 88 gross (85.9 net) producing natural gas wells. The average daily production for 2008 from the Corner/Leismer area was approximately 6.1 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 7.6 Bcf and probable reserves at 3.7 Bcf of natural gas for the Corner/Leismer area. In addition, we have 17.9 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 two 100 percent PET owned field booster compressors and one gas plant 32.5 percent owned by PET.

Cold Lake

The Cold Lake area is in northeast Alberta approximately 250 kilometres southeast of Fort McMurray. The Cold Lake area comprises 100,295 net acres (28.3 percent undeveloped) of which 1,280 gross (512 net) undeveloped acres are oil sands leases, including an average 75.1 percent working interest in 106 (79.7 net) producing natural gas wells. The average daily production for 2008 from the Cold Lake Area was approximately 5.6 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 7.8 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 129,776 net acres (48.6 percent undeveloped) with an average 76.9 percent working interest in 88 (67.7net) producing natural gas wells. The average daily production for 2008 from the Craigend area was approximately 4.9 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.4 Bcf and probable reserves at 2.3 Bcf for the Craigend area. Production from the Craigend area is processed through a 100 percent owned and operated gas plant.

Chard/Kettle/Quigley

The Chard/Kettle/Quigley area is in northeast Alberta approximately 80 kilometres south of Fort McMurray. The area comprises 123,880 net acres (50.0 percent undeveloped) including an average 94.9 percent working interest in 75 (71.2 net) producing natural gas wells. The average daily production for 2008 from the Chard area, including Kettle and Quigley, was approximately 4.6 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.7 Bcf and probable reserves at 1.4 Bcf of natural gas for the Chard/Kettle/Quigley area. In addition, we have 0.7 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.

Thornbury

The Thornbury area is in northeast Alberta approximately 75 kilometres southwest of Fort McMurray. The area comprises 44,172 net acres (26.7 percent undeveloped) including an average 79.7 percent working interest in 43 (34.3 net) producing natural gas wells. The average daily production for 2008 from the Thornbury area was approximately 3.5 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.6 Bcf and probable reserves at 1.7 Bcf of natural gas for the Thornbury 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. Production from the Thornbury area is processed through four gas plants and a field booster compressor owned by a third party.

East Side Other

Other assets within the East Side area comprise 119,926 net acres (47.9 percent undeveloped) of which 2,560 gross (2,560 net) undeveloped acres are oil sands leases in the Clyde area, including an average 54.3 percent working interest in 86 (46.7 net) producing natural gas wells. The average daily production for 2008 was approximately 2.9 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 4.3 Bcf and probable reserves at 1.2 Bcf of natural gas. In addition, we have 1.9 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the area is processed through a combination of non-operated plants where PET has a working interest and third party owned and operated plants.

West Side

Legend/East Legend

The Legend area, including East Legend, is approximately 110 kilometres northwest of Fort McMurray. The area comprises 204,947 net acres (63.7 percent undeveloped) of which 7,680 gross (7,680 net) undeveloped acres are oil sands leases, including an average 84.5 percent working interest in 97 (81.9 net) producing natural gas wells. The average daily production for 2008 from the Legend area was approximately 10.9 MMcf/d of natural gas, oil and liquids. The McDaniel Report evaluated our proved reserves at 14.9 Bcf and probable reserves at 4.6 Bcf of natural gas for the Legend area. In addition, we have 2.4 Bcf of probable reserves 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, that process the natural gas from this area.

Woodenhouse

The Woodenhouse area is located in northeast Alberta approximately 140 kilometres southwest of Fort McMurray and 300 kilometres north of Edmonton and comprises 139,334 net acres (52.6 percent undeveloped) of which 12,800 gross (12,800 net) undeveloped acres are oil sands leases, with an average 100 percent working interest in 44 gross (44.0 net) producing natural gas wells. The average daily production for 2008 from the Woodenhouse area was 7.9 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 7.6 Bcf and probable reserves at 5.4 Bcf for the Woodenhouse area. Current production in Woodenhouse is processed through a 100 percent PET owned and operated gas plant.

Liege

The Liege area is in northeast Alberta approximately 120 kilometres west of Fort McMurray. The area comprises 255,346 net acres (71.1 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 2008 from the Liege Area, including South, North and East Liege, was approximately 6.0 MMcf/d of natural gas. The McDaniel Report evaluated PET's total proved reserves at 5.8 Bcf and probable reserves at 9.5 Bcf of natural gas for the Liege area. Production from the Liege area is processed through the South Liege gas plant owned 80.5 percent by PET and one East Liege field booster compressor owned 90.9 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 122,157 net acres (72.2 percent undeveloped) of which 1,280 gross (256 net) undeveloped acres are oil sands leases, including an average 81.3 percent working interest in 36 gross (29.3 net) producing natural gas wells. The average daily production for 2008 from the Saleski area was approximately 4.8 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 13.7 Bcf and probable reserves at 3.9 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.

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 percent working interest in 23 gross (23.0 net) producing natural gas wells. The average daily production for 2008 from the Ells area was approximately 2.2 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 1.6 Bcf and probable reserves at 0.7 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.

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 91.2 percent working interest in 17 gross (15.5 net) producing natural gas wells. The average daily production for 2008 from the Teepee Creek area was 1.7 MMcf/d. The McDaniel Report evaluated our total proved reserves at 0.7 Bcf and probable reserves at 0.5 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.

West Side Other

Other assets within the West Side area in northeast Alberta comprise 88,171 net acres (76.5 percent undeveloped) including an average 51.2 percent working interest in 29 gross (14.9 net) producing natural gas wells. The average daily production for 2008 from the area was approximately 3.8 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.8 Bcf and probable reserves at 1.8 Bcf of natural gas for the West Side Other area. In addition, we have 3.6 Bcf of probable reserves shut-in as a result of the gas over bitumen issue in this area. Production from the other miscellaneous assets in the West Side area is processed through a combination of non-operated plants where PET has a working interest and third party plants.

Athabasca

Wabasca/Hoole

The Wabasca/Hoole area is located in northeast Alberta approximately 170 kilometres north of Edmonton. The area comprises 116,342 net acres (58.2 percent undeveloped) of which 18,560 gross (18,560 net) undeveloped acres are oil sands leases, with an average 100 percent working interest in 57 gross (57.0 net) producing natural gas wells. The average daily production for 2008 from the Wabasca/Hoole area was 13.2 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 17.2 Bcf and probable reserves at 6.2 Bcf for the Wabasca/Hoole area. Current production in Wabasca/Hoole is processed through a combination of 100 percent owned and operated compressor stations as well as third party facilities.

Marten Hills

The Marten Hills area is located in northeast Alberta approximately 220 kilometres north of Edmonton and comprises 165,994 net acres (56.0 percent undeveloped) of which 66,123 gross (66,123 net) undeveloped acres are oil sands leases, including an average 79.0 percent working interest in 111 gross (87.7 net) producing natural gas wells. The average daily production for 2008 from the Marten Hills area was 9.4 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 9.0 Bcfe of natural gas and probable reserves at 3.9 Bcfe of natural gas. Production in the Marten Hills area is processed through a combination of third party and operated facilities.

Calling Lake

The Calling Lake area is located in northeast Alberta approximately 230 kilometres north of Edmonton and comprises 69,308 net acres (36.7 percent undeveloped) with an average 57.7 percent working interest in 118 gross (68.0 net) producing natural gas wells. The average daily production for 2008 from the Calling Lake area was 7.7 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.3 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.

Peter Lake

The Peter Lake area is located in northeast Alberta and comprises 47,872 net acres (55.5 percent undeveloped) with an average 96.6 percent working interest in 27 gross (26.1 net) producing natural gas wells. The average daily production for 2008 from the Peter Lake area was 6.2 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.7 Bcf and probable reserves at 4.2 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.

Panny

The Panny area is located in northeast Alberta and comprises 166,320 net acres (81.9 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 35 gross (35.0 net) producing natural gas wells. The average daily production for 2008 from the Panny area was 5.6 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 7.5 Bcfe and probable reserves at 1.5 Bcfe for the Panny area. Current production in Panny is processed through a 100 percent PET owned gas processing facility.

Mitsue

The Mitsue area is located in northeast Alberta approximately 130 kilometres north of Edmonton and comprises 18,539 net acres (39.0 percent undeveloped) including an average 70.5 percent working interest in 29 gross (20.4 net) producing oil and natural gas wells. The average daily production for 2008 from the Mitsue area was 3.1 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 2.1 Bcfe of natural gas and probable reserves at 0.9 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.

Mistahae

The Mistahae area is located in northeast Alberta approximately 225 kilometres northwest of Edmonton and comprises 45,440 net acres (43.7 percent undeveloped) with an average 100.0 percent working interest in 38 gross (38.0 net) producing natural gas wells. The average daily production for 2008 from the Mistahae area was 2.8 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 2.7 Bcf and probable reserves at 2.0 Bcf for the Mistahae area. Current production in Mistahae is processed through a 100 percent PET owned and operated facility.

Darwin

The Darwin area is located in northeast Alberta approximately 100 kilometres northeast of Peace River and comprises 120,393 net acres (87.5 percent undeveloped) including and average 71.0 percent working interest in 17 gross (12.1 net) producing natural gas wells. The average daily production for 2008 from the Darwin area was 2.1 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 1.5 Bcf and probable reserves at 0.8 Bcf for the Darwin area. Current production in Darwin is processed through a non-operated plant where PET has a working interest.

Athabasca Other

The other assets in the Athabasca area in northeast Alberta comprise 170,173 net acres (71.5 percent undeveloped) of which 23,040 gross (23,040 net) undeveloped acres are oil sands leases in the Duncan area, including an average 24.2 percent working interest in 95 gross (23.0 net) producing natural gas wells. The average daily production for 2008 from these assets was approximately 2.1 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.0 Bcf and probable reserves at 0.9 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.

Southern District

Birchwavy West

Bruce

The Bruce area comprises 226,612 net acres (30.3 percent undeveloped) including an average 73.2 percent working interest in 214 (156.6 net) producing wells. The average daily production for 2008 from the Bruce area was 10.9 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 31.5 Bcfe and probable reserves at 36.3 Bcf. Production in Bruce is processed through one 91.5 percent owned and operated PET plant and third party plants.

Warwick

The Warwick area comprises 150,467 net acres (59.0 percent undeveloped) including an average 78.1 percent working interest in 73 gross (57.0 net) producing wells. The average daily production for 2008 from the Warwick area was 8.8 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 18.5 Bcf and probable reserves at 21.2 Bcf. Production in Warwick is processed through a combination of an owned and operated plant and third party plants.

Killam

The Killam area comprises 62,096 net acres (63.3 percent undeveloped) including an average 49.0 percent working interest in 80 gross (39.2 net) producing wells. The average daily production for 2008 from the Killam area was 2.8 MMcfe/d of natural gas, oil and liquids. The majority of the assets in this area were acquired through the Birchwavy Acquisition. The average daily production for 2008 from the Killam area was 2.8 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 3.3 Bcfe and probable reserves at 1.6 Bcf. Production in Killam is processed through a small 100 percent owned and operated plant and other third party plants.

Birchwavy East

Duvernay

The Duvernay area comprises 155,631 net acres (28.7 percent undeveloped) including an average 84.0 percent working interest in 142 gross (119.2 net) producing wells. The average daily production for 2008 from the Duvernay area was 13.1 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 24.2 Bcf and probable reserves at 45.3 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 128,433 net acres (23.3 percent undeveloped) including an average 95.0 percent working interest in 126 gross (119.7 net) producing wells. The average daily production for 2008 from the Manville area was 11.0 MMcfe/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 26.1 Bcfe and probable reserves at 17.0 Bcfe. Production in Manville is processed through two plants owned and operated by PET.

Viking Kinsella

The Viking Kinsella area comprises 96,635 net acres (51.3 percent undeveloped) including an average 72.5 percent working interest in 152 gross (110.2 net) producing wells. The average daily production for 2008 from the Viking Kinsella area was 5.4 MMcf/d of natural gas, oil and liquids. The McDaniel Report evaluated our total proved reserves at 10.0 Bcf and probable reserves at 3.1 Bcf. 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.

East Central Alberta

Other assets in the East Central Alberta area comprise 105,697 net acres (62.4 percent undeveloped) including an average 76.2 percent working interest in 68 gross (51.8 net) producing natural gas wells. The average daily production for 2008 from the east central Alberta area was 4.1 MMcfe/d of natural gas. The McDaniel Report evaluated our total proved reserves at 3.3 Bcf of natural gas and probable reserves at 2.7 Bcf of natural gas. Production in the East Central Alberta area is processed through an owned plant and several third party facilities.

Other Southern

Other non-core assets in the Southern area comprise 131,056 net acres (67.7 percent undeveloped) including an average 39.8 percent working interest in 185 gross (73.7 net) producing natural gas wells. The average daily production for 2008 from the West Central Saskatchewan area was 1.7 MMcfe/d of natural gas and heavy oil. The McDaniel Report evaluated our total proved reserves at 1.5 Bcfe and probable reserves at 0.9 Bcfe. Production is processed through a combination of 100 percent owned facilities and several third party facilities.

Severo Energy Corp.

Big Bend/Radway

In the third quarter of 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 122,773 net acres (47.6 percent undeveloped) with an average 41.2 percent working interest in 142 (58.5 net) producing natural gas wells. Including certain assets acquired in the Craigend/Radway/Stry Acquisition, the average daily production for 2008 from the Big Bend/Radway area was 7.0 MMcf/d of natural gas. The McDaniel Report evaluated our total proved reserves at 5.8 Bcf and probable reserves at 3.3 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, 2008.

	Producing		**Non-Producing[3][4]**	
Property	**Gross[1]**	**Net[2]**	**Gross[1]**	**Net[2]**
Northeast Alberta East Side				
Chard/Kettle/Quigley	75	71.2	58	48.8
Cold Lake	106	79.7	53	44.8
Corner/Leismer	88	85.9	140	135.6
Craigend	88	67.7	52	42.6
Thornbury	43	34.3	33	21.2
East Side Other[5]	86	46.7	128	62.6
East Side subtotal	486	385.4	464	355.5
Northeast Alberta West Side				
Ells	23	23.0	6	5.5
Legend	97	81.9	74	51.9
Liege	57	52.0	60	54.8
Saleski	36	29.3	32	28.3
Teepee Creek	17	15.5	14	12.0
Woodenhouse	44	44.0	62	62.0
West Side Other[6]	29	14.9	26	11.5

	Producing		Non-Producing[3][4]	
Property	**Gross[1]**	**Net[2]**	**Gross[1]**	**Net[2]**
West Side subtotal	303	260.5	274	226.1
Athabasca				
Darwin	17	12.1	25	18.8
Calling Lake	118	68.0	67	31.0
Marten Hills	111	87.7	51	37.8
Mistahae	38	38.0	8	8.0
Mitsue	29	20.4	17	11.6
Panny	35	35.0	11	11.0
Peter Lake	27	26.1	23	21.1
Wabasca/Hoole	57	57.0	64	56.5
Athabasca Other[7]	95	23.0	64	27.8
Athabasca subtotal	527	367.3	330	223.6
Birchwavy West				
Bruce	214	156.6	103	69.7
Killam	80	39.2	67	40.7
Warwick	73	57.0	88	72.2
Birchwavy West subtotal	367	252.8	258	182.7
Birchwavy East				
Duvernay	142	119.2	80	66.4
Mannville	126	119.2	75	72.3
Viking Kinsella	152	110.2	97	70.1
Birchwavy East subtotal	420	349.0	252	208.8
East Central Alberta	68	51.8	41	29.3
Other Southern[8]	185	73.7	77	53.5
Severo Energy Corp.				
Big Bend/Radway	142	58.5	84	65.7
TOTAL	**2,498**	**1,799.1**	**1,696**	**1,279.6**

(1) "**Gross**" refers to the number of wells, producing and non-producing, respectively, in which a working interest is held by PET. In addition PET held royalty interests 247 wells at December 31, 2008.

(2) "**Net**" refers to the aggregate of the numbers obtained by multiplying each gross well by the percentage working interest therein.

(3) "**Non-Producing**" refers to wells which are not currently producing either due to lack of facilities, markets or regulatory approval. This includes 170 gross (121.0 net) wells shut-in as a result of gas over bitumen regulatory rulings).

(4) Allowance for the abandonment costs associated with the well bores was made in the McDaniel Reports. There are 71 wells that are classified as service wells not included in the gross/net well count.

(5) **East Side Other** includes Bohn Lake, Clyde, Pony, Surmont, and Winefred.

(6) **West Side Other** includes Birch Tar, Hospital Creek, and Jean Lake.

(7) **Athabasca Other** includes Duncan, Portage, and Ryan.

(8) **Other Southern** includes Cabin Creek, Highvale, Saskatchewan, Sedalia, Craigmyle, Medicine Hat, Lacadena, Baldwinton, Kirkpatrick, Unity and Eyremore.

Acreage Information

The following table sets out our developed and undeveloped land holdings as at December 31, 2008. We do not have any material work commitments on any of our properties.

	Developed Acres		Undeveloped Acres(3)(4)	
Property	**Gross(1)**	**Net(2)**	**Gross(1)**	**Net(2)**
Northeast Alberta East Side				
Chard/Kettle/Quigley	72,320	61,932	71,680	61,948
Cold Lake	96,500	71,903	36,621	28,392
Corner/Leismer	145,530	141,349	182,790	170,630
Craigend	87,825	66,708	76,375	63,067
Thornbury	45,440	32,396	14,080	11,776
East Side Other	132,480	62,475	98,240	57,450
East Side subtotal	580,095	436,764	479,786	393,264
Northeast Alberta West Side				
Ells	11,520	10,560	32,640	29,920
Legend	97,920	74,470	162,560	130,477
Liege	85,280	73,799	211,040	181,547
Saleski	39,200	33,950	105,760	88,207
Teepee Creek	18,560	15,920	7,040	4,800
Woodenhouse	66,215	66,030	73,305	73,305
West Side Other	73,324	20,702	159,076	67,470
West Side subtotal	392,019	295,429	751,421	575,727
Athabasca				
Darwin	23,520	15,103	110,880	105,289
Calling Lake	85,120	43,867	39,200	25,441
Marten Hills	95,762	73,080	96,964	92,915
Mistahae	26,240	25,600	19,840	19,840
Mitsue	18,082	11,303	9,920	7,236
Panny	30,944	30,080	137,024	136,240
Peter Lake	25,155	21,292	28,899	26,580
Wabasca/Hoole	51,843	48,618	70,106	67,724
Athabasca other	148,480	48,517	161,440	121,656
Athabasca subtotal	505,145	317,460	674,272	602,921
Birchwavy West				
Bruce	225,995	157,959	82,665	68,652
Killam	50,870	22,772	59,838	39,324
Warwick	138,034	61,621	99,371	88,847
Birchwavy West subtotal	414,899	242,352	241,874	196,823
Birchwavy East				
Duvernay	152,677	110,959	52,684	44,672
Mannville	111,886	98,539	31,773	29,894
Viking Kinsella	114,675	47,063	62,970	49,573
Birchwavy East subtotal	379,238	256,561	147,427	124,139
East Central Alberta	64,379	39,781	81,339	65,915
Other Southern	86,867	42,297	129,079	88,759
Severo Energy Corp.				

Big Bend/Radway	125,638	64,300	86,156	58,473
TOTAL	2,548,279	1,694,944	2,591,353	2,106,021

(1) "Gross" means the total number of developed and undeveloped acres, respectively, in which we have an interest in respect of our current assets.
(2) "Net" means the aggregate of the numbers obtained by multiplying each gross acre by the actual percentage interest therein.
(3) During 2009 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.
(4) "Undeveloped Acres" refers to land where there are not any existing wells within the rights associated with those lands

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, 2009, 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.**

2009 McDaniel Forecast Production	**Natural Gas (MMcfe/d)**
Proved	162.3
Probable	14.7
Total Proved and Probable	177.0

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:

	2008 Year-Ended	**2008 Quarter Ended**			
	Dec 31	**Dec 31**	**Sept 30**	**June 30**	**Mar 31**
Average Daily Production Volume					
Natural Gas (MMcfe/d)	182.2	173.1	183.7	188.4	183.8
Average Prices Received ($/Mcfe)	8.18	7.61	8.78	9.00	7.29
Royalties Paid ($/Mcfe)	(1.38)	(1.14)	(1.61)	(1.71)	(1.06)
Operating Costs ($/Mcfe)	(1.81)	(1.65)	(1.94)	(1.67)	(1.98)
Transportation Costs ($/Mcfe)	(0.21)	(0.20)	(0.21)	(0.22)	(0.21)
Netback ($/Mcfe)	4.78	4.62	5.02	5.40	4.04

The following table indicates our average daily production from each of PET's core areas for the year ended December 31, 2008:

Property	2008 Production (MMcfe/d)
Northeast Alberta East Side	
Chard/Kettle/Quigley	4.6
Cold Lake	5.6
Corner/Leismer	6.0
Craigend	5.0
Thornbury	3.5
East Side Other	2.9
East Side subtotal	27.6
Northeast Alberta West Side	
Ells	2.2
Legend	10.9
Liege	6.0
Saleski	4.8
Teepee Creek	1.7
Woodenhouse	7.9
West Side Other	3.8
West Side subtotal	37.3
Athabasca	
Darwin	2.1
Calling Lake	7.7
Marten Hills	9.4
Mistahae	2.8
Mitsue	3.2
Panny	5.6
Peter Lake	6.2
Wabasca/Hoole	13.2
Athabasca Other	2.3
Athabasca subtotal	52.5
Birchwavy West	
Bruce	10.9
Killam	2.9
Warwick	8.8
Birchwavy West subtotal	22.6
Birchwavy East	
Duvernay	13.1
Mannville	11.0
Viking Kinsella	5.4
Birchwavy East subtotal	29.5
East Central Alberta	4.1
Other Southern	1.7
Severo	
Big Bend/Radway	7.0
TOTAL	**182.2**

Prospect Inventory

The Trust has identified numerous exploitation, development and low exposure exploration opportunities which are not recorded in the Reserve Report 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 2009 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 13 conventional natural gas wells, we are pursuing the drilling of over 45 gross wells as part of our 2009 capital expenditure budget. Further the Trust's evaluation of its prospect inventory has identified more than 600 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 700 workovers and secondary zone completions have been identified.

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

As a result of the Birchwavy Acquisition (See "**GENERAL DEVELOPMENT OF THE BUSINESS – Year Ended December 31, 2008"**), we have developed an inventory of unconventional Viking formation tight gas opportunities including 1,056 drilling and recompletion targets included in the McDaniel Reports well counts. We have also identified in excess of 1,400 future drilling locations that were not included in the McDaniel Reports, as those locations did not meet the criteria to be booked as reserves under NI 51-101. 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 322,123 gross (320,331 net) undeveloped oil sands leases throughout many of its shallow gas operating areas in Northeast Alberta including Duncan, Clyde, Cold Lake, Marten Hills, Liege, Panny, Saleski, Wabasca/Hoole, and Woodenhouse. The bitumen resource potential on these leases is internally estimated to exceed 6 billion barrels and will likely be developed in the long range plan using a variety of recovery techniques ranging from cold production to in-situ techniques such as SAG D technology. This resource represents tremendous future option value for Unitholders.

West Exploration Central Alberta

The Trust has accumulated 49,760 gross (49,760 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.

Capital Expenditures

The following tables summarize capital expenditures related to our activities for the year ended December 31, 2008:

($millions)	
Exploration and development expenditures	$ 99.5
Crown and freehold land purchases	26.6
Acquisitions	5.7
Dispositions	(24.2)
Other	1.6
Total	$ 109.2

Exploration and development expenditures for 2008 include approximately $9.2 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, 2008:

	Gross	**Net**
Light and Medium Oil	0	0.0
Natural Gas	91	75.4
Service	0	0.0
Dry	2	1.6
Total	93	77.0
Success Rate (%)	98	98
Exploratory	23	20.7
Development	70	56.3
Total	93	77.1

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 $363.2 million as at December 31, 2008. As at December 31, 2008, the undiscounted net salvage value of the Trust's gas plants, compressors and facilities was estimated at $163.0 million. The McDaniel Report includes an undiscounted amount of $151.0 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 a discounted amount of $119.5 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	$119.5	$77.1	$62.9	$55.9
Well abandonment costs for undeveloped reserves included in McDaniel Report	31.5	15.1	9.9	7.6
Well abandonment costs for Total Proved and Probable reserves included in McDaniel Report	151.0	92.2	72.8	63.5
Estimate of other abandonment and reclamation costs not included in McDaniel Report	212.2	159.5	136.6	124.1
Total estimated future abandonment and reclamation costs	**363.2**	**251.7**	**209.4**	**187.6**
Salvage value	(163.0)	(113.0)	(94.0)	(84.2)
Abandonment and reclamation costs, net of salvage	**200.2**	**138.7**	**115.4**	**103.4**
Well abandonment costs for developed reserves included in McDaniel Report(1)	(119.5)	(77.1)	(62.9)	(55.9)
Estimate of additional future abandonment and reclamation costs, net of salvage (1)	$80.7	$61.6	$52.5	$47.5

(1) 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 83 percent of our gas production at AECO-based market prices. The remaining 17 percent is directed to natural gas aggregator pools.

For a complete list of PET's outstanding financial instruments as at December 31, 2008, please see note 12 to the annual consolidated financial statements as at and for the year ended December 31, 2008. 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 9, 2009 are as follows.

Type of Contract	Volumes at AECO (GJ/d)	% of 2009 Budgeted Production(3)	Price ($/GJ)(1)	Current Forward Price ($/GJ)(2)	Term
Financial	81,000		7.18		March 2009
Physical	2,500		8.37		March 2009
Period Total	**83,500**	**41**	**7.96**	**4.48**	**March 2009**
Financial	107,500		7.13		April – October 2009
Period Total	**107,500**	**52**	**7.13**	**4.47**	**April – October 2009**
Financial	100,000		8.13		November 2009 – March 2010
Period Total	**100,000**	**49**	**8.13**	**6.16**	**November 2009 – March 2010**
Financial	102,500		7.31		April – October 2010
Period Total	**102,500**	**50**	**7.31**	**6.14**	**April – October 2010**
Physical	10,000		7.75		November 2010 – March 2011
Financial	92,500		7.94		November 2010 – March 2011
Period Total	**102,500**	**50**	**7.92**	**7.29**	**November 2010 – March 2011**

(1) 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. Included in the March 2009 volume summaries is a collar to sell forward 5,000 GJ/d at a floor price of $7.00 per GJ at AECO and a ceiling price of $8.00 per GJ. As the current AECO forward price is below the floor of the collar, the floor price is used in the weighted average price calculation.
(2) Average AECO forward price for April through December 2009 as at March 9, 2009 is $4.53 per GJ.
(3) Calculated using 205,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes.

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 $3.4 million have been received and included in 2008 funds flows in respect of these transactions. Call option contracts outstanding as of March 9, 2009 are as follows.

Type of Contract	Volumes at AECO (GJ/d)	% of 2009 Budgeted Production(1)	Strike Price ($/GJ)	Current Forward Price ($/GJ)	Term
Sold call	5,000	3	8.50	6.16	November 2009 – March 2010
Sold call	5,000	3	7.75	6.14	April – October 2010
Sold call	12,500	6	9.00	7.29	November 2010 – March 2011

(1) Calculated using 205,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes.

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 9, 2009 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. New legislation passed in June 2007 will impose 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 19.2 MMcf/d for 2008. 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.

In 2008 the Trust received $20.8 million in gas over bitumen royalty adjustments, of which $5.6 million was classified as revenue and $15.1 million was recorded on the Trust's balance sheet. Cumulative royalty adjustments received to December 31, 2008 total $98.3 million.

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 20th, 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 produces 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. Oil sands activity in the area has increased through 2007 and 2008. Although the ERCB has given PET no indication that they are reconsidering the permission to produce this gas, there is a risk that oil sands operators could influence the ERCB and reopen the issue of gas production from these pools. Production from Legend and East Legend is currently approximately 10.9 MMcfd.

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 they are 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.

PET has filed an application to pursue a technical solution which involves a gas storage project in the Corner/Leismer area. The shut-in McMurray gas pool is an ideal candidate for cycling methane. To date certain bitumen owners at Corner/Leismer have withheld their support for the project. The hearing in respect of the application has been cancelled at PET's request in order to facilitate additional investigations and discussions with third parties.

RISK FACTORS

Investors should carefully consider the risk factors set out below and consider all other information contained herein and in the Trust's other public filings before making an investment decision.

Shut in Natural Gas Reserves

Recent decisions by the AEUB have brought into question our ability to continue to produce natural gas from all of the Wabiskaw and McMurray formations in certain parts of the Athabasca Oil Sands Area in Northeast Alberta. The AEUB has ordered shut-in of some of our production and reserves in this area.

The AEUB has also indicated that it believes there is a need to assess whether additional gas production should be curtailed in situations similar to those considered at hearings to-date and whether there is a need for a broad bitumen conservation strategy in all areas where natural gas production may interfere with eventual bitumen recovery. It is possible that such a strategy, when drafted and implemented by the ERCB (formerly AEUB), will affect future natural gas production from reservoirs owned by the Trust and located within the gas over bitumen areas of concern as 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.

While we have no significant additional production recommended for shut-in by any party or the ERCB at this time and royalty adjustments are being received for production currently shut-in, we cannot ensure that additional production will not be shut-in in the future or that we will be able to negotiate adequate compensation for having to shut-in any such production. This could have a material adverse effect on the amount of income available for distribution to Unitholders. (See "**REGULATORY RULINGS – GAS OVER BITUMEN")**.

Solution Gas Ownership

A portion of PET's natural gas production is from properties where third parties hold bitumen rights. Certain of these third parties have suggested that "solution gas" exists within the bitumen and that therefore this solution gas is the property of the bitumen rights holder. If this is proven to be correct, and if it is demonstrated that this solution gas has been or may continue to be produced in association with the recovery of PET's conventional natural gas rights, these facts may give rise to a third party claim for compensation. A successful claim in this regard may have a material adverse effect on the Trust's business, financial condition and operations.

Exploration, Development and Production Risks

Oil and natural gas operations involve many risks that even a combination of experience, knowledge and careful evaluation may not be able to overcome. The long-term commercial success of the Trust depends on its ability to find, acquire, develop and commercially produce oil and natural gas reserves. Without the continual addition of new reserves, any existing reserves the Trust may have at any particular time, and the production there from will decline over time as such existing reserves are exploited. A future increase in the Trust's reserves will depend not only on its ability to explore and develop any properties it may have from time to time, but also on its ability to select and acquire suitable producing properties or prospects. No assurance can be given that the Trust will be able to continue to locate satisfactory properties for acquisition or participation. Moreover, if such acquisitions or participations are identified, management of the Trust may determine that current markets, terms of acquisition and participation or pricing conditions make such acquisitions or participations uneconomic. There is no assurance that further commercial quantities of oil and natural gas will be discovered or acquired by the Trust.

Future oil and natural gas exploration may involve unprofitable efforts, not only from dry wells, but also from wells that are productive but do not produce sufficient petroleum substances to return a profit after drilling, operating and other costs. Completion of a well does not assure a profit on the investment or recovery of drilling, completion and operating costs. In addition, drilling hazards or environmental damage could greatly increase the cost of operations, and various field operating conditions may adversely affect the production from successful wells. These conditions include delays in obtaining governmental approvals or consents, shut-ins of connected wells resulting from extreme weather conditions, insufficient storage or transportation capacity or other geological and mechanical conditions. While diligent well supervision and effective maintenance operations can contribute to maximizing production rates over time, production delays and declines from normal field operating conditions cannot be eliminated and can be expected to adversely affect revenue and cash flow levels to varying degrees.

Oil and natural gas exploration, development and production operations are subject to all the risks and hazards typically associated with such operations, including hazards such as fire, explosion, blowouts, cratering, sour gas releases and spills, each of which could result in substantial damage to oil and natural gas wells, production facilities, other property and the environment or personal injury. In particular, the Trust may explore for and produce sour natural gas in certain areas. An unintentional leak of sour natural gas could result in personal injury, loss of life or damage to property and may necessitate an evacuation of populated areas, all of which could result in liability to the Trust. In accordance with industry practice, the Trust is not fully insured against all of these risks, nor are all such risks insurable. Although the Trust maintains liability insurance in an amount that it considers consistent with industry practice, the nature of these risks is such that liabilities could exceed policy limits, in which event the Trust could incur significant costs. Oil and natural gas production operations are also subject to all the risks typically associated with such operations, including encountering unexpected formations or pressures, premature decline of reservoirs and the invasion of water into producing formations. Losses resulting from the occurrence of any of these risks may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Global Financial Crisis and Recession

Recent market events and conditions, including disruptions in the international credit markets and other financial systems and the deterioration of global economic conditions, have caused significant volatility to commodity prices. These conditions worsened in 2008 and are continuing in 2009, causing a loss of confidence in the broader U.S. and global credit and financial markets and resulting in the collapse of, and government intervention in, major banks, financial institutions and insurers and creating a climate of greater volatility, less liquidity, widening of credit spreads, a lack of price transparency, increased credit losses and tighter credit conditions. Notwithstanding various actions by governments, concerns about the general condition of the capital markets, financial instruments, banks, investment banks, insurers and other financial institutions caused the broader credit markets to further deteriorate and stock markets to decline substantially. These factors have negatively impacted company valuations and will impact the performance of the global economy going forward.

The global recession has had a dramatic negative impact on the industrial use of natural gas, oil and petroleum products. Commodity prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing global credit and liquidity concerns.

Prices, Markets and Marketing

The marketability and price of oil and natural gas that may be acquired or discovered by the Trust is and will continue to be affected by numerous factors beyond its control. The Trust's ability to market its oil and natural gas may depend upon its ability to acquire space on pipelines that deliver natural gas to commercial markets. The Trust may also be affected by deliverability uncertainties related to the proximity of its reserves to pipelines and processing and storage facilities and operational problems affecting such pipelines and facilities as well as extensive government regulation relating to price, taxes, royalties, land tenure, allowable production, the export of oil and natural gas and many other aspects of the oil and natural gas business.

The prices of oil and natural gas prices may be volatile and subject to fluctuation. Any material decline in prices could result in a reduction of the Trust's net production revenue. The economics of producing from some wells may change as a result of lower prices, which could result in reduced production of oil or gas and a reduction in the volumes of the Trust's reserves. The Trust might also elect not to produce from certain wells at lower prices. All of these factors could result in a material decrease in the Trust's expected net production revenue and a reduction in its oil and gas acquisition, development and exploration activities. Prices for oil and gas are subject to large fluctuations in response to relatively minor changes in the supply of and demand for oil and gas, market uncertainty and a variety of additional factors beyond the control of the Trust. These factors include economic conditions, in the United States and Canada, the actions of OPEC, governmental regulation, political stability in the Middle East and elsewhere, the foreign supply of oil and gas, risks of supply disruption, the price of foreign imports and the availability of alternative fuel sources. Any substantial and extended decline in the price of oil and gas would have an adverse effect on the Trust's carrying value of its reserves, borrowing capacity, revenues, profitability and cash flows from operations and may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Petroleum prices are expected to remain volatile for the near future as a result of market uncertainties over the supply and the demand of these commodities due to the current state of the world economies, OPEC actions and the ongoing credit and liquidity concerns. Volatile oil and gas prices make it difficult to estimate the value of producing properties for acquisition and often cause disruption in the market for oil and gas producing properties, as buyers and sellers have difficulty agreeing on such value. Price volatility also makes it difficult to budget for and project the return on acquisitions and development and exploitation projects.

In addition, bank borrowings available to the Trust may, in part, be determined by the Trust's borrowing base. A sustained material decline in prices from historical average prices could reduce the Trust's borrowing base, therefore reducing the bank credit available to the Trust which could require that a portion, or all, of the Trust's bank debt be repaid.

The Trust manages commodity price uncertainty through financial hedges and physical forward sale arrangements. There is a credit risk associated with counterparties with which the Trust may contract.

Failure to Realize Anticipated Benefits of Acquisitions and Dispositions

The Trust makes acquisitions and dispositions of businesses and assets in the ordinary course of business. Achieving the benefits of acquisitions depends in part on successfully consolidating functions and integrating operations and procedures in a timely and efficient manner as well as the Trust's ability to realize the anticipated growth opportunities and synergies from combining the acquired businesses and operations with those of the Trust. The integration of acquired business may require substantial management effort, time and resources and may divert management's focus from other strategic opportunities and operational matters. Management continually assesses the value and contribution of services provided and assets required to provide such services. In this regard, non-core assets are periodically disposed of, so that the Trust can focus its efforts and resources more efficiently. Depending on the state of the market for such non-core assets, certain non-core assets of the Trust, if disposed of, could be expected to realize less than their carrying value on the financial statements of the Trust.

Operational Dependence

Other companies operate some of the assets in which the Trust has an interest. As a result, the Trust has limited ability to exercise influence over the operation of those assets or their associated costs, which could adversely affect the Trust's financial performance. The Trust's return on assets operated by others therefore depends upon a number of factors that may be outside of the Trust's control, including the timing and amount of capital expenditures, the operator's expertise and financial resources, the approval of other participants, the selection of technology and risk management practices.

Project Risks

The Trust manages a variety of small and large projects in the conduct of its business. Project delays may delay expected revenues from operations. Significant project cost over-runs could make a project uneconomic. The Trust's ability to execute projects and market oil and natural gas depends upon numerous factors beyond the Trust's control, including:

- the availability of processing capacity;
- the availability and proximity of pipeline capacity;
- the availability of storage capacity;
- the supply of and demand for oil and natural gas;
- the availability of alternative fuel sources;
- the effects of inclement weather;
- the availability of drilling and related equipment;
- unexpected cost increases;
- accidental events;
- currency fluctuations;
- changes in regulations;
- the availability and productivity of skilled labour; and
- the regulation of the oil and natural gas industry by various levels of government and governmental agencies.

Because of these factors, the Trust could be unable to execute projects on time, on budget or at all, and may not be able to effectively market the oil and natural gas that it produces.

Competition

The petroleum industry is competitive in all its phases. The Trust competes with numerous other organizations in the search for, and the acquisition of, oil and natural gas properties and in the marketing of oil and natural gas. The Trust's competitors include oil and natural gas companies that have substantially greater financial resources, staff and facilities than those of the Trust. The Trust's ability to increase its reserves in the future will depend not only on its ability to explore and develop its present properties and developed land, but also on its ability to select and acquire other suitable producing properties or prospects for exploratory drilling. Competitive factors in the distribution and marketing of oil and natural gas include price and methods and reliability of delivery and storage. Competition may also be presented by alternate fuel sources.

Regulatory

Oil and natural gas operations (exploration, production, pricing, marketing and transportation) are subject to extensive controls and regulations imposed by various levels of government, which may be amended from time to time. (See **"Industry Conditions"**). Governments may regulate or intervene with respect to price, taxes, royalties and the exportation of oil and natural gas. Such regulations may be changed from time to time in response to economic or political conditions. The implementation of new regulations or the modification of existing regulations affecting the oil and natural gas industry could reduce demand for natural gas and crude oil and increase the Trust's costs, any of which may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. In order to conduct oil and gas operations, the Trust will require licenses from various governmental authorities. There can be no assurance that the Trust will be able to obtain all of the licenses and permits that may be required to conduct operations that it may wish to undertake.

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Environmental

All phases of the oil and natural gas business present environmental risks and hazards and are subject to environmental regulation pursuant to a variety of federal, provincial and local laws and regulations. Environmental legislation provides for, among other things, restrictions and prohibitions on spills, releases or emissions of various substances produced in association with oil and natural gas operations. The legislation also requires that wells and facility sites be operated, maintained, abandoned and reclaimed to the satisfaction of applicable regulatory authorities. Compliance with such legislation can require significant expenditures and a breach of applicable environmental legislation may result in the imposition of fines and penalties, some of which may be material. Environmental legislation is evolving in a manner expected to result in stricter standards and enforcement, larger fines and liability and potentially increased capital expenditures and operating costs. The discharge of oil, natural gas or other pollutants into the air, soil or water may give rise to liabilities to governments and third parties and may require the Trust to incur costs to remedy such discharge. Although the Trust believes that it will be in material compliance with current applicable environmental regulations no assurance can be given that environmental laws will not result in a curtailment of production or a material increase in the costs of production, development or exploration activities or otherwise have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Kyoto Protocol

Canada is a signatory to the United Nations Framework Convention on Climate Change and has ratified the Kyoto Protocol established thereunder to set legally binding targets to reduce nationwide emissions of carbon dioxide, methane, nitrous oxide and other emissions referred to as "greenhouse gases". The Trust's exploration and production facilities and other operations and activities emit greenhouse gases which will require the Trust to comply with the new regulatory framework announced on March 10, 2008 by the Federal Government which is intended to force large industries to reduce emissions of greenhouse gases, in addition to the proposed *Clean Air Act* (Canada) of 2006 and Alberta's recently enacted *Climate Change and Emissions Management Act* and *Specified Gas Emitters Regulation*.

There has been much public debate with respect to Canada's ability to meet these targets and the Government's strategy or alternative strategies with respect to climate change and the control of greenhouse gases. Implementation of strategies for reducing greenhouse gases whether to meet the limits required by the Kyoto Protocol or as otherwise determined could have a material impact on the nature of oil and natural gas operations, including those of the Trust.

Given the evolving nature of the debate related to climate change and the control of greenhouse gases and resulting requirements, it is not possible to predict the impact on the Trust and its operations and financial condition. The direct or indirect costs of these regulations may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. (See "**Regulatory**").

Variations in Foreign Exchange Rates and Interest Rates

North American oil and gas markets are effectively denominated in United States dollars and the price received by Canadian producers is therefore affected by the Canadian/U.S. dollar exchange rate, which will fluctuate over time. In recent years, the Canadian dollar has increased materially in value against the United States dollar although the Canadian dollar has recently decreased from such levels. Material increases in the value of the Canadian dollar relative to the U.S. dollar will negatively impact the Trust's production revenues. Future Canadian/United States exchange rates could accordingly impact the future value of the Trust's reserves as determined by independent evaluators.

To the extent that the Trust engages in risk management activities related to foreign exchange rates, there is a credit risk associated with counterparties with which the Trust may contract.

An increase in interest rates could result in a significant increase in the amount the Trust pays to service debt, which could negatively impact the market price of the Trust Units.

Substantial Capital Requirements

The Trust anticipates making substantial capital expenditures for the acquisition, exploration, development and production of oil and natural gas reserves in the future. If the Trust's revenues or reserves decline, it may not have access to the capital necessary to undertake or complete future exploration and development programs and fund future acquisitions. In addition, uncertain levels of near term industry activity coupled with the present global credit crisis exposes the Trust to additional access to capital risk. There can be no assurance that debt or equity financing, or cash generated by operations will be available or sufficient to meet these requirements or for other corporate purposes or, if debt or equity financing is available, that it will be on terms acceptable to the Trust. The inability of the Trust to access sufficient capital for its operations could have a material adverse effect on the Trust's business financial condition, results of operations and prospects.

The Trust's cash flow from its reserves may not be sufficient to fund its ongoing activities at all times. From time to time, the Trust may require additional financing in order to carry out its oil and gas acquisition, exploration and development activities. Failure to obtain such financing on a timely basis could cause the Trust to forfeit its interest in certain properties, miss certain acquisition opportunities and reduce or terminate its operations. If the Trust's revenues from its reserves decrease as a result of lower oil and natural gas prices or otherwise, it will affect the Trust's ability to expend the necessary capital to replace its reserves or to maintain its production. If the Trust's cash flow from operations is not sufficient to satisfy its capital expenditure requirements, there can be no assurance that additional debt or equity financing will be available to meet these requirements or, if available, on terms acceptable to the Trust. Continued uncertainty in domestic and international credit markets could materially affect the Trust's ability to access sufficient capital for its capital expenditures and acquisitions, and as a result, may have a material adverse effect on the Trust's ability to execute its business strategy and on its business, financial condition, results of operations and prospects.

Issuance of Debt

From time to time the Trust may enter into transactions to acquire assets or the shares of other organizations. These transactions may be financed in whole or in part with debt, which may increase the Trust's debt levels above industry standards for oil and natural gas companies of similar size. Depending on future exploration and development plans, the Trust may require additional equity and/or debt financing that may not be available or, if available, may not be available on favourable terms. Neither the Trust's articles nor its by-laws limit the amount of indebtedness that the Trust may incur. The level of the Trust's indebtedness from time to time, could impair the Trust's ability to obtain additional financing on a timely basis to take advantage of business opportunities that may arise.

Hedging

From time to time the Trust may enter into agreements to receive fixed prices on its oil and natural gas production to offset the risk of revenue losses if commodity prices decline; however, if commodity prices increase beyond the levels set in such agreements, the Trust will not benefit from such increases and the Trust may nevertheless be obligated to pay royalties on such higher prices, even though not received by it, after giving effect to such agreements. Similarly, from time to time the Trust may enter into agreements to fix the exchange rate of Canadian to United States dollars in order to offset the risk of revenue losses if the Canadian dollar increases in value compared to the United States dollar; however, if the Canadian dollar declines in value compared to the United States dollar, the Trust will not benefit from the fluctuating exchange rate. In the event that these contractual arrangements are significantly "out-of-the-money" The Trust may be subject to margin calls related to these transactions and may not have available cash or credit to cover these margin calls. There is also credit risk associated with the counterparties with which the Trust may contract.

Availability of Drilling Equipment and Access

Oil and natural gas exploration and development activities are dependent on the availability of drilling and related equipment (typically contracted from third parties) in the particular areas where such activities will be conducted. Demand for such limited equipment or access restrictions may affect the availability of such equipment to the Trust and may delay exploration and development activities.

Title to Assets

Although title reviews may be conducted prior to the purchase of oil and natural gas producing properties or the commencement of drilling wells, such reviews do not guarantee or certify that an unforeseen defect in the chain of title will not arise to defeat the Trust's claim which may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Reserve Estimates

There are numerous uncertainties inherent in estimating quantities of oil, natural gas and natural gas liquids reserves and the future cash flows attributed to such reserves. The reserve and associated cash flow information set forth herein are estimates only. In general, estimates of economically recoverable oil and natural gas reserves and the future net cash flows therefrom are based upon a number of variable factors and assumptions, such as historical production from the properties, production rates, ultimate reserve recovery, timing and amount of capital expenditures, marketability of oil and gas, royalty rates, the assumed effects of regulation by governmental agencies and future operating costs, all of which may vary materially from actual results. For those reasons, estimates of the economically recoverable oil and natural gas reserves attributable to any particular group of properties, classification of such reserves based on risk of recovery and estimates of future net revenues associated with reserves prepared by different engineers, or by the same engineers at different times, may vary. The Trust's actual production, revenues, taxes and development and operating expenditures with respect to its reserves will vary from estimates thereof and such variations could be material.

Estimates of proved reserves that may be developed and produced in the future are often based upon volumetric calculations and upon analogy to similar types of reserves rather than actual production history. Recovery factors and drainage areas were estimated by experience and analogy to similar producing pools. Estimates based on these methods are generally less reliable than those based on actual production history. Subsequent evaluation of the same reserves based upon production history and production practices will result in variations in the estimated reserves and such variations could be material.

In accordance with applicable securities laws, the Trust's independent reserves evaluator has used forecast prices and costs in estimating the reserves and future net cash flows as summarized herein. Actual future net cash flows will be affected by other factors, such as actual production levels, supply and demand for oil and natural gas, curtailments or increases in consumption by oil and natural gas purchasers, changes in governmental regulation or taxation and the impact of inflation on costs.

Actual production and cash flows derived from the Trust's oil and gas reserves will vary from the estimates contained in the reserve evaluation, and such variations could be material. The reserve evaluation is based in part on the assumed success of activities the Trust intends to undertake in future years. The reserves and estimated cash flows to be derived there from contained in the reserve evaluation will be reduced to the extent that such activities do not achieve the level of success assumed in the reserve evaluation. The reserve evaluation presented in the Reserves Data (See **"STATEMENT OF RESERVES DATA AND OTHER OIL AND GAS INFORMATION – disclosure of Reserves Data)** is effective as of a specific effective date, December 31, 2008, and has not been updated and thus does not reflect changes in the Trust's reserves since that date.

Insurance

The Trust's involvement in the exploration for and development of oil and natural gas properties may result in the Trust becoming subject to liability for pollution, blow outs, leaks of sour natural gas, property damage, personal injury or other hazards. Although the Trust maintains insurance in accordance with industry standards to address certain of these risks, such insurance has limitations on liability and may not be sufficient to cover the full extent of such liabilities. In addition, such risks are not, in all circumstances, insurable or, in certain circumstances, the Trust may elect not to obtain insurance to deal with specific risks due to the high premiums associated with such insurance or other reasons. The payment of any uninsured liabilities would reduce the funds available to the Trust. The occurrence of a significant event that the Trust is not fully insured against, or the insolvency of the insurer of such event, may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Geo-Political Risks

The marketability and price of oil and natural gas that may be acquired or discovered by the Trust is and will continue to be affected by political events throughout the world that cause disruptions in the supply of oil and natural gas. Conflicts, or conversely peaceful developments, arising in the Middle-East, and other areas of the world, have a significant impact on the price of oil and natural gas. Any particular event could result in a material decline in prices and therefore result in a reduction of the Trust's net production revenue.

In addition, the Trust's oil and natural gas properties, wells and facilities could be subject to a terrorist attack. If any of the Trust's properties, wells or facilities are the subject of terrorist attack it may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. The Trust will not have insurance to protect against the risk from terrorism.

Dilution

The Trust may make future acquisitions or enter into financings or other transactions involving the issuance of securities of the Trust which may be dilutive.

Management of Growth

The Trust may be subject to growth-related risks including capacity constraints and pressure on its internal systems and controls. The ability of the Trust to manage growth effectively will require it to continue to implement and improve its operational and financial systems and to expand, train and manage its employee base. The inability of the Trust to deal with this growth may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Expiration of Licences and Leases

The Trust's properties are held in the form of licences and leases and working interests in licences and leases. If the Trust or the holder of the licence or lease fails to meet the specific requirement of a licence or lease, the licence or lease may terminate or expire. There can be no assurance that any of the obligations required to maintain each licence or lease will be met. The termination or expiration of the Trust's licences or leases or the working interests relating to a licence or lease may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects.

Seasonality

The level of activity in the Canadian oil and gas industry is influenced by seasonal weather patterns. Wet weather and spring thaw may make the ground unstable. Consequently, municipalities and provincial transportation departments enforce road bans that restrict the movement of rigs and other heavy equipment, thereby reducing activity levels. Also, certain oil and gas producing areas are located in areas that are inaccessible other than during the winter months because the ground surrounding the sites in these areas consists of swampy terrain. Seasonal factors and unexpected weather patterns may lead to declines in exploration and production activity which could impact the production and future revenues of the Trust. In addition high demand for equipment in winter months for areas limited to winter access could result in increased costs and the inability to execute the Trust’s desired exploration and development programs.

Third Party Credit Risk

The Trust may be exposed to third party credit risk through its contractual arrangements with its current or future joint venture partners, marketers of its petroleum and natural gas production, ~~financial~~ commodity price and currency hedge contract counterparties, and other parties. In the event such entities fail to meet their contractual obligations to the Trust, such failures may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. In addition, poor credit conditions in the industry and of joint venture partners may impact a joint venture partner's willingness to participate in the Trust's ongoing capital program, potentially delaying the program and the results of such program until the Trust finds a suitable alternative partner.

Conflicts of Interest

Certain directors of the Administrator are also directors of other oil and gas companies and as such may, in certain circumstances, have a conflict of interest requiring them to abstain from certain decisions. Conflicts, if any, will be subject to the procedures and remedies of the ABCA. (See "**DIRECTORS AND OFFICERS – Conflicts of Interest**".)

Reliance on Key Personnel

The Trust's success depends in large measure on certain key personnel. The loss of the services of such key personnel may have a material adverse effect on the Trust's business, financial condition, results of operations and prospects. The contributions of the existing management team to the immediate and near term operations of the Trust are likely to be of central importance. In addition, the competition for qualified personnel in the oil and natural gas industry is intense and there can be no assurance that the Trust will be able to continue to attract and retain all personnel necessary for the development and operation of its business. Investors must rely upon the ability, expertise, judgment, discretion, integrity and good faith of the management of the Administrator.

Operations in Other Jurisdictions

Our operations and the expertise of our management are currently focused on conventional shallow and unconventional tight gas production and development in the Western Canadian Sedimentary Basin. In the future, we may acquire oil and gas properties outside this geographic area. In addition, the Trust Indenture does not limit the activities of the Trust to oil and gas production and development, and the Trust could acquire other energy related assets, such as oil and natural gas processing plants or pipelines. Expansion of our activities into new areas may present new additional risks or alternatively, significantly increase the exposure to one or more of the present risk factors, which may result in future operational and financial conditions of the Trust being adversely affected.

Participation in Other Business Activities

The Trust Indenture does not limit our activities to oil and gas production and development. We could acquire other energy related assets such as natural gas processing plants or pipelines, an interest in an oil sands project or participate in gas marketing commercial ventures such as natural gas storage. Expansion of our activities into new areas may present additional risks or, alternatively, significantly increase the exposure to one or more of the present risk factors. In either case, our future operational and financial conditions could be materially adversely affected.

Lender Limitations on Distributions on Trust Units and Cash Redemptions of Trust Units

Under the terms of the credit facility with our lenders, if the lenders determine that our borrowing base under the facility has been exceeded by the amount loaned and assuming there is not a demand for repayment we will be precluded from providing distributions on Trust Units and from paying cash for redemptions of Trust Units until our borrowing base no longer is in a shortfall position. Our lenders may also restrict our ability to pay distributions when we are in breach or default of agreements with the lenders.

The lenders will be provided with security over substantially all of our assets. If we become unable to pay our debt service charges or otherwise commit an event of default such as bankruptcy, the lender may foreclose on or sell the working interests.

Disposition of Trust Units

The right to redeem Trust Units will not be the primary mechanism for Unitholders to liquidate their investments. Further, there may not be an active trading market for the Trust Units that would facilitate other sales. Generally, we will not redeem in cash more than $100,000 of Trust Units in any one calendar month. Instead we will pay such excess redemption amount by the issuance of promissory notes of PET which will be unsecured, subordinated to all of our indebtedness and due and payable five years after issuance. No market is expected to develop for the promissory notes. Our ability to pay redemptions in cash or to make payment on promissory notes may be further restricted by our lenders.

A return on an investment in the Trust is not comparable to the return on an investment in a fixed-income security. The recovery of an initial investment in the Trust is at risk, and the anticipated return on such investment is based on many performance assumptions. Although we intend to make distributions of available cash to holders of Trust Units, these cash distributions may be reduced or suspended. The actual amount distributed will depend on numerous factors including: our financial performance and the financial performance of POT, debt obligations, working capital requirements and future capital requirements. In addition, the market value of the Trust Units may decline if the Trust's cash distributions decline in the future, and that market value decline may be material.

It is important for an investor to consider the particular risk factors that may affect the industry in which it is investing, and therefore the stability of the distributions that it receives.

The after-tax return from an investment in Trust Units to Unitholders subject to Canadian income tax can be made up of both a return on capital and a return of capital. That composition may change over time, thus affecting an investor's after-tax return. Returns on capital are generally taxed as ordinary income in the hands of a Unitholder. Returns of capital are generally tax-deferred (and reduce the Unitholder's cost base in the Trust Unit for tax purposes).

Dilution

To maintain or expand our natural gas reserves we will need to finance capital expenditures and property acquisitions. Consequently, you may suffer dilution as a result of any future offering of Trust Units or securities convertible into Trust Units.

Statutory Rights Related to Trust Units

The Trust Units do not represent a traditional investment and should not be viewed by investors as "shares" in either the Administrator or the Trust. Corporate law does not govern the Trust and the rights of Unitholders. Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation including, for example, the right to bring "oppression" or "derivative" actions. The rights of Unitholders are specifically set forth in the Trust Indenture. In addition, trusts are not defined as recognized entities within the definitions of legislation such as the Bankruptcy and Insolvency Act (Canada) and the Companies' Creditors Arrangement Act (Canada). As a result, in the event of an insolvency or restructuring, a Unitholder's position as such may be quite different than that of a shareholder of a corporation.

Personal Liability

Unitholders are not protected from our liabilities to the same extent that a shareholder would be protected from a corporation's liabilities. For example, personal liability of Unitholders may arise from claims in tort or claims for taxes against PET. Unlike many other royalty trusts and income funds, the Trust's 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. As a result, ownership of Trust Units may expose you to personal liability.

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 PET. 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. This legislation has not been subject to interpretation by the courts in the Province of Alberta. (See "**DESCRIPTION OF CAPITAL STUCTURE – Unitholder Liability"**)

Non-Resident Ownership Restrictions

The Trust Indenture restricts the ownership of Trust Units by Unitholders who are non-residents of Canada for the purposes of the *Income Tax Act* (Canada). Unitholders who are non-residents of Canada face the risk of being forced to sell some or all of their Trust Units in order to comply with these restrictions.

Generally Accepted Accounting Principles ("GAAP")

GAAP requires that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in our consolidated financial statements. The accounting policies may result in non-cash charges to net income and write-downs of net assets in the financial statements. Such non-cash charges and write-downs may be viewed unfavourably by the market and result in an inability to borrow funds and/or may result in a decline in the Trust Unit price. The carrying value of property, plant and equipment, the carrying value of goodwill and the value of hedging instruments are some of the items which are subject to valuation and potential non-cash write-downs.

Interest Rates

Variations in interest rates could result in a significant increase in the amount we pay to service its debt resulting in a decrease in distributions to Unitholders. In addition the Trust may enter derivative financial instruments to fix the interest rate on a portion of its debt. To the extent that interest rates decrease in the future the Trust would not benefit from such decreases to the extent it had previously fixed interest rates.

Permitted Investments

We may invest in certain permitted investments of which the market value may fluctuate. For example, the prices of Canadian government securities, bankers' acceptances and commercial paper react to economic developments and changes in interest rates. Commercial paper is also subject to issuer credit risk. Other permitted investments in energy-related entities will be subject to the general risks of investing in equity securities. These include the risks that the financial condition of issuers may become impaired or that the energy sector may suffer a market downturn. Securities markets in general are affected by a variety of factors including: governmental, environmental and regulatory policies; inflation and interest rates; economic cycles; and global, regional and national events. The value of the Trust Units could be affected by adverse changes in the market values of permitted investments.

Changes in Tax Legislation

The treatment of mutual fund trusts could be changed in a manner which adversely affects Unitholders. If we cease to qualify as a "mutual fund trust" under the *Income Tax Act* (Canada), the Trust Units will cease to be qualified investments for registered retirement savings plans, registered education savings plans, deferred profit sharing plans and registered retirement income funds.

Income tax laws, or other laws or government incentive programs relating to the natural gas industry such as the treatment of mutual fund trusts and resource taxation may be changed or interpreted in a manner that adversely affects us and our Unitholders. Tax authorities having jurisdiction over us or the Unitholders may disagree with how we calculate our income for tax purposes or could change administrative practices to our detriment or to the detriment of Unitholders.

The Administrator intends that PET will continue to qualify as a mutual fund trust for purposes of the *Income Tax Act* (Canada) until such time as the Trust decides to convert to a corporation as may be encouraged by the changes to the Trust Tax Legislation announced on October 31, 2006. (See "**GENERAL DEVELOPMENT OF THE BUSINESS – History and Development –** Trust Tax Legislation**"**. We may not, however, always be able to satisfy any future requirements for the maintenance of mutual fund trust status. Should our status as a mutual fund trust be lost or successfully challenged by a relevant tax authority, certain adverse consequences may arise for us and our Unitholders. Some of the significant consequences of losing mutual fund trust status are as follows:

- We would be taxed on certain types of income distributed to Unitholders including income generated by the royalties held by us. Payment of this tax may have adverse consequences for some Unitholders, particularly Unitholders who are not residents of Canada and residents of Canada who are otherwise exempt from Canadian income tax;
- We would cease to be eligible for the capital gains refund mechanism available under Canadian tax legislation;
- Trust Units held by Unitholders who are not residents of Canada would become taxable Canadian property. These non-resident holders would be subject to Canadian income tax on any gains realized on a disposition of Trust Units held by them; and
- Trust Units would not constitute qualified investments for registered retirement savings plans ("RRSPs"), registered retirement income funds ("RRIFs"), registered education savings plans ("RESPs") or deferred profit sharing plans ("DPSPs"). If, at the end of any month, one of these exempt plans holds Trust Units that are not qualified investments, the plan must pay a tax equal to 1 percent of the fair market value of the Trust Units at the time the Trust Units were acquired by the exempt plan. An RRSP or RRIF holding non-qualified Trust Units would be subject to taxation on income attributable to the Trust Units. If an RESP holds non-qualified Trust Units it may have its registration revoked by the Canada Revenue Agency.

The Administrator may take certain measures in the future to the extent it believes necessary to ensure that we maintain our status as a mutual fund trust. These measures could be adverse to certain holders of Trust Units, particularly "non-residents" of Canada as defined in the *Income Tax Act* (Canada).

Trust Units as Qualified investments under the *Income Tax Act* (Canada)

The *Income Tax Act* (Canada) imposes penalties for the acquisition or holding of non-qualified investments by registered retirement savings plans, deferred profit sharing plans, registered retirement income funds and registered education savings plans. Should the Trust Units become non-qualified investments for the purpose of being held in such plans, the plans might become liable for penalties and the market for the Trust Units may be adversely affected.

Trust Tax Legislation

The Trust Tax Legislation results in a tax applicable at the trust level on certain income from publicly traded mutual fund trusts at rates of tax comparable to the combined federal and provincial corporate tax and treats distributions as dividends to the Unitholders. Existing trusts were provided a four-year transition period and, subject to the qualification below, the new tax will apply in January 2011. Once applied the new tax will affect PET's funds flow and may impact cash distributions from the Trust.

In light of the foregoing, the Trust Tax Legislation has reduced the value of the Trust's Units, which increases the cost to PET of raising capital in the public capital markets for acquisition opportunities. PET's access to capital markets could also be affected by this legislation. In addition, the Trust Tax Legislation is expected to place PET and other Canadian energy trusts at a competitive disadvantage relative to industry competitors, including U.S. master limited partnerships, which will continue to not be subject to entity-level taxation. There can be no assurance that PET will be able to reorganize its legal and tax structure to substantially mitigate the expected impact of the Trust Tax Legislation.

Trust Structure

Currently, PET's assets are well suited to the cash distributing model of the trust structure, however the changes in the trust tax legislation have affected our Unitholder base and our access to capital. In order to maximize short term and long term value for Unitholders we may make changes to our operations and assets as well as our capital structure. This may cause us to consider alternative structures for the Trust.

Changes in Distributions

The board of directors of the Trust's Administrator assess the distribution on a monthly basis based on cash flow projections which incorporate PET's base production forecasts, current hedges and physical forward natural gas sales, the forward market for natural gas prices, and the Trust's capital spending program and projected production additions. Future distributions are subject to change as dictated by changes in commodity price markets, operations and future business development opportunities and may vary materially from previous distributions.

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
2006		
January 31, 2006	February 15, 2006	$0.240
February 28, 2006	March 15, 2006	$0.240
March 31, 2006	April 17, 2006	$0.240
April 28, 2006	May 15, 2006	$0.240
May 31, 2006	June 15, 2006	$0.240
June 30, 2006	July 17, 2006	$0.240
July 31, 2006	August 15, 2006	$0.200
August 31, 2006	September 15, 2006	$0.200
September 29, 2006	October 16, 2006	$0.200
October 31, 2006	November 15, 2006	$0.200
November 30, 2006	December 15, 2006	$0.200
December 29, 2006	January 15, 2007	$0.200
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

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.

Period	High	Low	Volume
2008			
January	7.30	6.13	9,531,996
February	8.25	6.75	16,043,927
March	8.51	7.28	12,581,831
April	9.95	8.15	13,448,549
May	10.25	9.01	11,519,122
June	10.19	9.16	9,097,815
July	10.15	7.95	9,470,623
August	9.15	7.43	8,033,737
September	8.75	7.01	12,595,230
October	7.44	4.80	14,539,347
November	6.44	4.89	6,059,023
December	6.44	4.89	6,059,023
2009			
January	5.75	4.75	6,151,442
February	4.90	3.40	7,319,778

The 8% Convertible Debentures are listed and posted for trading on the TSX and trade under the symbol **PMT.DB**. The following sets out the price range and trading volume of the 8% Convertible Debentures as reported by the TSX for the periods indicated.

Period	High	Low	Volume
2008			
January	100.25	100.05	77,000
February	100.00	98.5	12,000
March	102.89	101.02	314,000
April	104.00	102.50	58,000
May	104.00	101.02	23,000
June	101.92	100.00	44,000
July	102.50	101.77	30,000
August	102.00	101.73	31,000
September	102.00	101.05	236,000
October	100.50	84.50	98,000
November	99.98	95.01	305,000
December	99.00	96.00	93,000
2009			
January	99.50	97.50	544,500
February	100.00	97.62	64,000

The 2005 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.

Period	High	Low	Volume
2008			
January	96.38	85.52	830,000
February	99.75	93.26	452,000
March	100.00	97.15	812,000
April	100.50	97.56	1,015,000
May	100.00	97.00	751,000
June	102.49	99.00	1,306,000
July	101.97	99.50	807,000
August	102.50	100.00	771,000
September	101.96	90.06	650,000
October	96.45	80.00	513,000
November	95.00	80.01	441,000
December	94.00	73.00	617,000
2009			
January	95.00	90.00	387,000
February	92.00	87.00	706,000

The 2006 6.25% Convertible Debentures are listed and posted for trading on the TSX and trade under the symbol **PMT.DB.B**. 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.

Period	High	Low	Volume
2008			
January	92.00	83.00	1,659,000
February	96.00	90.01	1,037,000
March	97.96	94.00	1,214,000
April	99.0	95.02	2,333,000
May	98.5	95.32	2,005,000
June	99.9	97.00	5,078,000
July	100.00	96.50	1,527,000
August	99.97	97.34	1,274,000
September	99.48	95.00	1,142,000
October	94.50	65.01	743,000
November	85.50	71.02	661,000
December	81.00	60.50	1,933,000
2009			
January	84.99	70.00	602,000
February	83.00	70.60	776,000

The 2007 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.

Period	High	Low	Volume
2008			
January	89.89	83.01	549,000
February	92.00	87.01	8,539,000
March	94.93	89.51	2,158,000
April	95.49	91.28	1,606,000
May	96.50	94.01	3,127,000
June	98.99	95.00	4,023,000
July	98.49	96.06	3,503,000
August	97.00	95.26	2,652,000
September	96.35	90.00	1,340,000
October	91.00	62.00	1,053,000
November	75.95	65.00	4,482,000
December	70.00	58.00	3,965,000
2009			
January	82.50	59.00	2,810,000
February	75.00	68.00	7,937,000

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-Residents 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 banknote 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. 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 it receives 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 it 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 will pay such cash distributions on 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 certificates (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

To the knowledge of the Administrator, none of our securities are held in escrow.

DIRECTORS AND OFFICERS

Unitholders will vote, or withhold from voting, on an annual basis to authorize and direct the Trustee to pass a resolution on our behalf for the election of directors of the Board of the Administrator proposed by management of the Administrator. None of the constating documents of the Administrator restrict the directors' ability to vote compensation to themselves or any members of their body provided a regular quorum is present at a meeting of directors. The Administrator's by-laws grant broad borrowing powers to the Board which the Board may delegate to any one or more directors or officers of the Administrator. The Administrator does not have any mandatory retirement age for members of the Board and does not require them to own any Trust Units to be qualified to act as a director. The directors and officers of the Administrator are set out in the table below as are their municipalities of residence and present positions with the Administrator:

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 Alberta, Canada	Executive Chairman of the Board and Director since June 28, 2002	Mr. Riddell has been the Executive Chairman of the Board of Directors of the Administrator since June 28, 2002, and was the Chief Executive Officer until May 9, 2005. He has been 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 a director and the Chief Executive Officer of MGM Energy Corp., a public oil and gas company. He is Chairman of the Board of Trilogy Energy Ltd., the administrator of Trilogy Energy Trust. Mr. Riddell also sits on the Board of Directors of Newalta Inc. and is a Director of Tourmaline Oil Corp. (a private oil and gas exploration and development company).
Susan L. Riddell Rose(4) 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.
Cameron R. Sebastian 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 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 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 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 this, 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 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 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.
Karen A. Genoway(2)(3)(5)(7) Alberta, Canada	Director since June 28, 2002	Ms. Genoway is a professional landman with over 26 years experience in the oil and natural gas industry. Currently, she is the Vice President, Land for Onyx Oil & Gas Ltd., a private oil and gas company. From February 2001 to January 2002, she was Vice President of Request Management Inc., manager of Request Income Trust. Ms. Genoway was with the Enerplus Group of Companies where she held the positions of Senior Vice President (1997 to 2000), Vice President Land (1989 – 1997) and Land Manager (1987 – 1989).
Randall E. Johnson(1)(3)(5)(7) 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. 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.
Robert A. Maitland(1)(3)(5)(7) Alberta, Canada	Director since February 7, 2008	Mr. Maitland is a Chartered Accountant with 34 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.

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
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 this, Mr. Nelson held the consecutive positions of Vice President, Operations and President and Director with Summit Resources Limited from July 1996 to June 2002.
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. Mr. Peltier is currently a director of Bow Valley Energy Ltd., a position he has held since May 2005 and previously from 1996 through February 2002 and has been a director for Masters Energy Inc. since October 2004. He was a director of Ember Resources Inc. (July 2005 to September 2008); trustee of Gienow Windows and Doors Income Fund (October 2004 to November 2007); 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).
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, 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).

(1) Member of the Audit Committee
(2) Member of the Reserves Committee.
(3) Member of the Corporate Governance Committee.
(4) Member of the Environmental, Health and Safety Committee.
(5) Member of the Compensation Committee.
(6) The terms of office of all directors of the Administrator will expire on the date of the next annual Unitholders' meeting of the Administrator.
(7) 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 32,191,610 voting securities as of March 10, 2009 representing 28.50 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

Mr. Riddell is a director and executive officer of PRL. From 1992 to 2008, PRL was the general partner of T.T.Y. Paramount Partnership No.5 (“TTY”), a limited partnership, which was an unlisted reporting issuer in certain provinces of Canada. TTY was established in 1980 to conduct oil and gas exploration and development activities, but had not carried on operations since 1984 and currently had only nominal assets. A cease trade order against TTY was issued by the Quebec Securities Commission in 1999 for failing to file the June 30, 1998 interim financial statements in Quebec. The cease trade order was revoked on April 9, 2008. TTY was dissolved in 2008.

Other than as disclosed above, no current director or 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 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.

In addition, no current director or 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, within the last ten years prior to the date of this document, 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.

No current director or 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 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 such 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 substances 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, 2009, 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 housed in 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 recently 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 has established 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 $536,000, in 2008 and $571,000 in 2007.

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 $5,000 in 2008 and $142,500 in 2007. In both 2007 and 2008, we incurred fees for quarterly reviews and services provided with respect to a prospectus.

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 $12,305 in 2008 and $20,195 in 2007.

These services relate to the determination and reporting of taxability of security distributions for each of Canada and the United States and the preparation and filing of Canadian trust and corporate income tax returns.

All Other Fees

No fees were billed in each of the last two fiscal years for products and services provided by our external auditor other than services reported above.

DISTRIBUTION REINVESTMENT AND OPTIONAL TRUST UNIT PURCHASE PLAN

PET has established a Distribution Reinvestment and Optional Trust Unit Purchase Plan (the "**DRIP Plan**"). Under the DRIP Plan, eligible Unitholders have the opportunity to reinvest monthly cash distributions to acquire additional Trust Units at 94 percent of the treasury purchase price, which is defined as the daily volume weighted average trading prices of the Trust Units for the 10 trading days immediately preceding a distribution payment date. As well, subject to thresholds and restrictions described in the DRIP Plan, it contains a provision for the purchase of additional Trust Units with optional cash payments of up to $100,000 per participant per financial year of PET to acquire additional Trust Units at the same six percent discount to the treasury purchase price. The aggregate number of DRIP Units that may be purchased in any financial year of PET will be limited based on the number of Trust Units issued and outstanding at the start of the financial year. As of March 9, 2009, the aggregate number of Trust Units that have been issued under the DRIP is 12,840,833. The aggregate number of Trust Units available for distribution under the DRIP Plan as of March 9, 2009 was 3,489,454. Participants will not have to pay any brokerage fees or service charges in connection with the purchase of Trust Units under the DRIP Plan.

We reserve the right to determine the number of Trust Units available for purchase under the DRIP Plan for any distribution payment date. In respect of any distribution payment date, if fulfilling all of the elections under the DRIP Plan would result in our exceeding the limitations on the number of Trust Units issuable under the DRIP Plan, then we will accept elections for the purchase of DRIP Units on such distribution payment: (i) first, from participants electing the distribution reinvestment option; and (ii) second, from participants electing the cash payment option. If we are unable to accept all elections in a particular category, then we will prorate purchases of DRIP Units on the applicable distribution payment date among all participants in that category according to the number of Trust Units they seek to purchase.

Effective March 2008, the Trust suspended the availability of Trust Units under the optional cash purchase component of the DRIP. On October 17, 2008, PET announced that there would be no Trust Units available under the distribution reinvestment component of the DRIP for the Trust's October distribution payable on November 17, 2008 and until further notice. As a result of this suspension, Unitholders that had elected to participate in the DRIP in the past and were currently enrolled will instead receive cash distributions on the distribution payment dates. Should the Trust elect to reinstate the DRIP, Unitholders that were enrolled at suspension and remain enrolled at reinstatement will automatically resume participation in the DRIP. PET's distribution policy remains unchanged.

LEGAL PROCEEDINGS

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.

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 since the beginning of our last completed financial year or in any proposed transaction which has materially affected or will materially affect us or the Administrator other than (i) certain insiders purchasing common shares of Severo Energy Corp. in 2006 by way of private placement and (ii) as disclosed herein.

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 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:

1. the Trust Indenture;
2. the POT Indenture;
3. the POT Royalty Agreement;
4. the 8% Convertible Debenture Trust Indenture;
5. the 2005 6.25% Convertible Debenture Trust Indenture;
6. the 2006 6.25% Convertible Debenture Trust Indenture;
7. the 2007 6.50% 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 AEUB

The AEUB 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 AEUB.

The most significant regulatory impact on us has been from the AEUB'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, as applicable, 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 financial statements and management's discussion and analysis for the year ended December 31, 2008. 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 RESERVES DATA AND OTHER INFORMATION 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, 2008, 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 10, 2009

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

January 29, 2009

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, 2008. The reserves data consists of the following;

   (a) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2008 using forcast process and costs and the related estimated future net revenue; and

   (b) Proved and proved plus probable oil and gas reserves estimated as at December 31, 2008 using constant prices and costs and the related estimated future net revenue.

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, 2008, 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
January 29, 2009	Canada	-	1,300,685	-	1,300,685

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.
6. We have no responsibility to update our report 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.

Executed as to our report referred to above:

MCDANIEL & ASSOCIATES CONSULTANTS LTD.

/s/ P.A. Welch

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

Calgary, Alberta

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

January 29, 2009

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, 2008. The reserves data are estimates of proved reserves and probable reserves and related future net revenue as at December 31, 2008, 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, 2008, 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
January 29, 2009	Canada	-	32,921	-	32,921

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.

/s/ 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.