2008 ANNUAL RESULTS

PARAMOUNT
ENERGY TRUST

CANADA'S ONLY 100% NATURAL GAS TRUST

Paramount Energy Trust ("PET") is a high-yield income investment in the Canadian energy industry. Based in Calgary, PET operates as a full-cycle exploration and production company with operations concentrated in shallow natural gas in northeast and east central Alberta. PET's business plan revolves around a sustainable cash flow distributing model, directing capital to low exposure exploration and exploitation opportunities within the base assets to maintain production, and acquiring synergistic assets and investing in new ventures for growth. Cash distributions of $13.264 per Trust Unit, more than one and a half times the Trust's net asset value at inception, have been paid to Unitholders in PET's six year history. At the same time, production per Trust Unit has remained relatively flat while reserves, undeveloped land and net asset value per Trust Unit have increased. Most importantly, PET has successfully grown its intrinsic inventory of opportunities to add production, reserves and value in the future. While we live in challenging times, these measures substantiate a business plan that is sustainable and endorse a bright future to continue to create value for Unitholders.

This report contains forward-looking information with respect to Paramount Energy Trust ("PET" or the "Trust"). Implicit in this information are assumptions regarding natural gas prices, production, royalties and expenses which, although considered reasonable by PET at the time of preparation, may prove to be incorrect. This forward looking information is based on certain assumptions that involve a number of risks and uncertainties and are not guarantees of future performance. Actual results could differ materially as a result of changes in PET's plans, changes in commodity prices, general economic, market, regulatory and business conditions as well as production, exploration, development and operating performance., capital, administrative and operating costs, regulations and other risks associated with oil and gas operations. There is no guarantee by PET that actual results achieved will be the same as those forecast herein.

2009 estimates are based on forecast financial and operating results incorporating PET's revised annual capital budget approved March 10, 2009, an estimate of first quarter 2009 actual results and the forward market for natural gas prices at that date, adjusted for PET's gas price management contracts projected to settle in 2009. At that date, the average AECO forward price for April to December 2009 was $4.78 per Mcf.

PRESIDENT'S MESSAGE

2008 – a year of extremes. Extremes in equity markets, as every major North American stock market index reached an all-time high. Extremes in commodity prices, as the world witnessed the all-time peak for oil with a barrel of West Texas Intermediate selling for an unprecedented price of $147.27 US, and natural gas traded on NYMEX for $13.70 US per MMBtu in early July. Extremes in natural gas supply with the step-change that horizontal drilling and multi-stage fracture technology brought to shale gas resource plays in North America. Then the crash; starting first with credit markets, then commodity prices, then equities – and the markets continue to struggle to regain balance and composure. Extremes in demand destruction, as economically crippling effects of the credit crisis have led to the worst global recession since the Great Depression. And finally, extremes in the speed and severity of the oil and gas price collapse that appear to be taking the Canadian oil patch into the worst slow down since the National Energy Policy was enacted in 1982.

One of PET's greatest achievements is our legacy of managing our business through adversity. These are tough economic times, compounded by low commodity prices, but they underscore the importance of strong leadership, teamwork and a sound business plan. Our track record of managing challenging times is one we have earned through our solid team values of accountability and perseverance. We successfully navigated the gas over bitumen regulatory issue that threatened almost half of our production very early in our existence as an energy trust. With a multi-faceted approach, we brought stakeholders together to find a manageable solution when the Alberta Energy and Utilities Board deemed that some gas production from the Wabiskaw-McMurray formations in the Athabasca Oil Sands Area could have a detrimental effect on future bitumen recovery. Along with the income trust sector, we are still working through the federal government's about-face on the flow-through tax model of the trust structure. Significant effort has been put forth to find an alternative that both preserves the benefits of the trust structure in the development of Canada's maturing hydrocarbon resources, and addresses the concerns of government. Solutions exist, however little progress has been made to convince the current Conservative regime to work with industry on this matter. Now, as the world is caught in this severe economic downturn, it is crucial to sharpen our focus on every aspect of our business to ensure the prudent management of the Trust, and to remain attuned to the opportunities when the challenges may seem overwhelming. Adaptability and innovative thinking have always been a hallmark at PET, and with the full dedication of our skilled and entrepreneurial team, all of our efforts are focused on being a top performing energy investment.

The solid foundation of our success has been the inherent characteristics of our base assets. PET's natural gas producing properties are mature and predictable, with an abundance of low risk opportunities that allow us to bring production onstream cost-effectively. Our production addition cost metrics continue to be among the best in the sector at $15,000 to $20,000 per flowing barrel of oil equivalent per day. We have worked hard to improve our reserve addition costs as well, driving project costs down and recognition of reserves up to achieve top quartile finding, development and acquisition costs for the second consecutive year. Lowering the cost of our operations will continue to be an important focus in 2009, while ensuring that our strong safety and environmental records remain a top priority.

A portion of PET's growth has come from accretive acquisitions which have added production, reserves and a wealth of new opportunities. When combined with land purchases proximal to our core assets targeting concentric exploration ideas, our prospect inventory is extensive. Over the past year we have developed tools internally to characterize and rank our prospect inventory, and our technical teams have developed micro-level evaluations of each of our properties. Today, PET has 3.8 million net acres of land, of which 2.1 million are considered "undeveloped" – but those lands contain over 2,400 gross risked potential drilling opportunities ranging from drill-ready locations to concepts and leads. In addition to projects captured in the year-end 2008 independent reserve report, our prospect inventory offers a net risked, recoverable shallow gas reserve potential of 230 Bcfe. That reserve potential will grow as concepts and leads are converted to drill-ready prospects with seismic definition, technological advancements and the step-wise expansion of infrastructure. We have 487 Bcfe (proved and probable) of reserves on our books, giving us a total net risked resource endowment of close to 720 Bcfe, and that does not include the enormous bitumen resource captured by the Trust's oil sands leases and the significant exploration potential on PET's deep basin lands. Our booked reserves and risk-discounted shallow gas prospect inventory alone translates into a reserve life index of greater than 12 years on a proved, probable and possible basis.

As the industry moves closer to the 2011 implementation of a new direct taxation regime for trusts, we are evolving our business model and our asset base. Exploration and new ventures are now an important component of our business plan. We have invested in new ventures which are synergistic with our base assets and where innovative technologies and execution excellence will capture future value and growth. Unitholders are now exposed to unconventional tight shallow gas plays where technology is advancing to open up large and long-term resource plays, and to vast bitumen resources where future technology will unlock this option value. Technical work is underway on several depleted gas pools to investigate the economic return of commercial gas storage projects. We have also initiated technical studies to assess the injection of carbon dioxide emissions (CO_2 sequestration and storage) as a strategy to reduce greenhouse gas emissions, particularly emissions from oil sands projects in northeast Alberta, and to possibly improve gas pool recoveries. We are driven to capture the potential of these new ventures in order to create value and growth for years to come. Further to that focus, we have devoted effort to expanding the breadth of our inventory of opportunities to include higher impact resource-style plays. To that end, in 2008 PET established a position in over 47,000 net acres of exploratory acreage in the deep basin in west central Alberta targeting primarily Triassic objectives. If successful, the economic return to Unitholders could be material.

Fundamental to our business plan, and of critical importance in the current uncertain economic climate, is balance sheet management. Over the past two years, we have taken bold steps to reduce our net debt by a substantial $120 million from its high in mid-year 2007 after the closing of the Birchwavy acquisition in east central Alberta. This has been achieved with minimal dilution to production and reserves through the sale of tangible assets and surplus equipment, management of forward sales contracts and the sale of minor non-core properties. In addition, PET's proactive natural gas price risk management program has positioned us with a financial asset that today has a forward mark-to-market value of $154 million. Options to further strengthen our financial position are also being pursued; these include divesting additional non-core assets, seeking partners for several new venture opportunities, and remaining vigilant to opportunities to crystallize further gains from our hedging activities.

While 2008 was a year of extremes, the Trust, guided by a sound business plan, has once again demonstrated its ability to perform through adversity and to position for the future. PET's evolution is well underway for moving forward as a yield-oriented entity beyond 2011. People of many disciplines work together to manage and build our business of supplying energy to society; and our efforts can be seen in the many new benchmarks we have achieved in expanding our base of opportunities and exposing our Unitholders to some of the most exciting new ventures in the industry today. Collectively, our people bring together knowledge, experience and a passion for excellence. Rest assured, our hands are firmly on the reins as we ride through these challenging times. Our full attention is on the pursuit of value creation and growth to sustain PET as a high performing investment in the Canadian energy industry.

Susan Riddell Rose

March 10, 2009

2008 AT A GLANCE

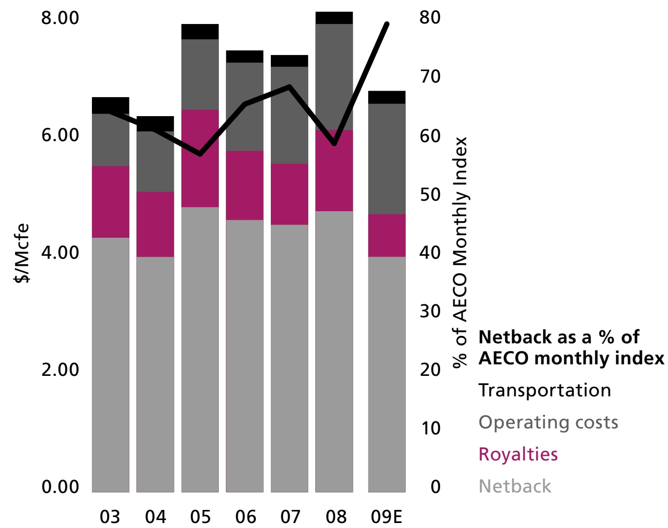
Maximize Cash Flow

- Production increased seven percent to a record 182.2 MMcfe/d in 2008 as a result of a full year of production from the Birchwavy acquisition in east central Alberta in June 2007 and successful capital programs during the year, and including the net disposition of 2.0 MMcfe/d of production from non-core assets.
- PET's average realized gas price was $8.18 per Mcfe in 2008, a 10 percent increase from $7.44 per Mcfe in 2007 and slightly higher than the average AECO monthly index price of $8.13 per Mcf for 2008.
- The Trust continued to execute on its proactive natural gas price risk management strategy to provide a measure of stability to realized prices and cash flows despite significant volatility in natural gas prices. For April 2009 through March 2011 PET has an average of 98.1 MMcf/d of gas production hedged at an average price of $7.96 per Mcf. The current forward market for natural gas at AECO for that period is $5.79 per Mcf.
- Funds flow increased 15 percent to a record $275.4 million or $2.47 per Trust Unit in 2008 as compared to $239.1 million or $2.44 per Trust Unit for 2007 due primarily to increased production levels and higher realized natural gas prices, partially offset by higher royalties and operating expenses. Funds flow netbacks averaged $4.13 per Mcfe in 2008 versus $3.82 per Mcfe in 2007.

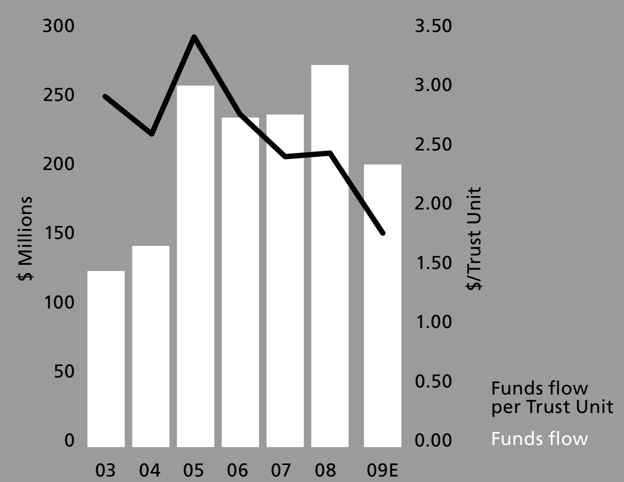
Asset Optimization

- Capital spending on exploration and development activities totaled $126.1 million in 2008. In total 93 gross wells were drilled (77.0 net) with a 98 percent success rate. Total capital expenditures including acquisitions, net of dispositions and excluding corporate asset additions were $107.6 million.
- In 2008, the Trust added 35.5 Bcfe of proved reserves and 8.3 Bcfe of probable reserves for total reserve additions of 43.8 Bcfe of proved and probable reserves. After production of 66.7 Bcfe, proved and probable reserves decreased four percent to 487.1 Bcfe. Reserve additions largely offsetting production were due to the successful reinvestment in exploration and development spending programs, representing approximately 39 percent of the Trust's 2008 funds flow, excluding the exploratory land investment in west central Alberta.
- Including future development capital and an additional $6.8 million recorded in 2009 for an acquisition which closed in January 2009 but for which reserves were booked in 2008, PET realized finding, development and acquisition costs of $2.62 per Mcfe ($15.72 per boe) for proved reserves and $2.52 per Mcfe ($15.12 per boe) for proved and probable reserves in 2008. Excluding the acquisition of the several large exploration blocks in west central Alberta for $19.1 million upon which no reserve-adding activities were pursued in 2008, finding, development and acquisition costs for 2008 totaled $2.08 per Mcfe ($12.48 per boe) for proved reserves and $2.08 per Mcfe ($12.48 per boe) for proved and probable reserves, representing full cycle costs on PET's base shallow gas business. This translates into a recycle ratio on the base assets of 2.0 in 2008.

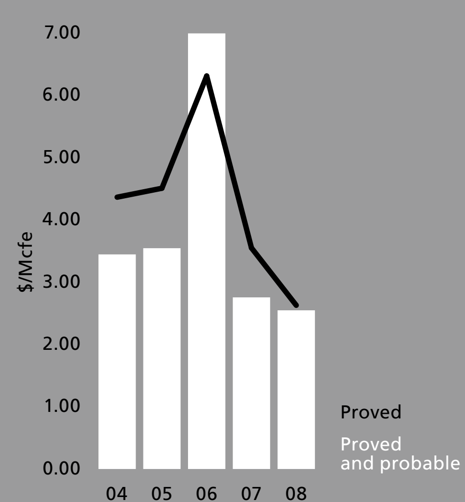
OPERATING NETBACK



FUNDS FLOW



FINDING, DEVELOPMENT AND ACQUISITION COSTS



Accretive Acquisitions

- PET closed dispositions of non-core assets representing 2.4 MMcfe/d of working interest and royalty interest production and 0.6 MMcf/d of shut-in gas over bitumen deemed production for proceeds of $24.2 million.
- Several small consolidating acquisitions were negotiated proximal to the Trust's core assets for a net $5.7 million.
- Reserve additions from acquisitions, net of divestitures, were 0.3 Bcfe of proved reserves and a net disposition of 0.1 Bcfe of proved and probable reserves.

New Ventures

- The Trust invested $19.1 million in 2008 for several large parcels of exploratory Crown acreage in west central Alberta targeting deep basin-style tight gas resource plays. This area is outside of the Trust's core asset base and offers a number of high impact exploration opportunities which complement PET's existing lower risk shallow gas prospect inventory.
- PET acquired 132,480 net acres of oil sands acreage for $3.1 million in 2008, bringing PET's total oil sands acreage in northeast Alberta to 320,651 net acres. The Trust has acquired oil sands leases in several different project areas at Panny, Woodenhouse, Liege, Ells, Wabiskaw/Hoole, Marten Hills and Clyde, primarily in the vicinity of PET's natural gas production operations, and is in the process of preparing plans to evaluate the resource potential and future development scenarios of these leases.

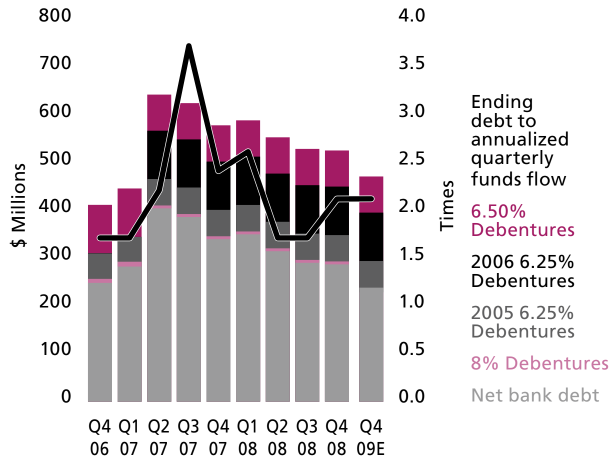
Healthy Balance Sheet

- PET strengthened its balance sheet substantially during 2008. As a result of funds flows in excess of distributions and capital expenditures, and non-core property dispositions, PET reduced bank debt 15 percent from $335.7 million at December 31, 2007 to $284.8 million drawn on its $410 million bank facility at December 31, 2008. Including PET's convertible debentures of $236.0 million, total debt dropped to $520.9 million at December 31, 2008, lowering the total net debt to annualized quarterly funds flow ratio from 2.4 to 2.1 at year end.

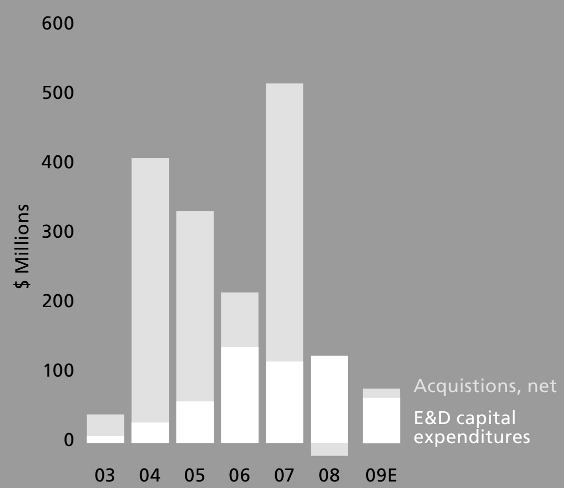
Maximize Distributions and Unitholder Value

- Distributions paid for 2008 were $1.20 per Trust Unit for a total of $133.9 million, representing a payout ratio of 48.6 percent of funds flow.
- In response to a substantial decrease in the trading price of the Trust's securities, PET announced on October 17, 2008 the suspension of Trust Units available under the DRIP plan and instituted normal course issuer bids to repurchase its outstanding Trust Units and convertible debentures (the "Bids"). PET has not repurchased any securities under the Bids to date.
- PET's net asset value discounted at five percent at year end 2008 was estimated at $10.63 per Trust Unit. Aside from the nominal undeveloped land value assigned based on current land sale prices, this excludes the value of the Trust's extensive low risk prospect inventory which does not meet the requirements for reserve booking under National Instrument 51-101 but which is pursued annually with capital spending. On a risked basis, the Trust has identified almost 500 workovers and secondary zone completions, more than 450 conventional shallow gas drilling prospects and close to 1,000 future unconventional tight shallow gas drilling locations not included in the independent reserve report prepared by McDaniel and Associates that will be pursued as they are technically refined and as economic factors permit.

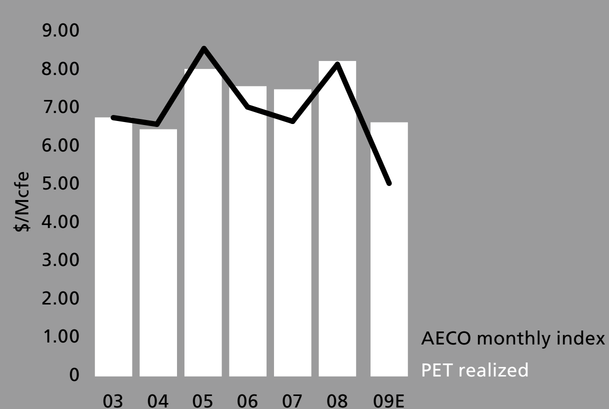
NET DEBT



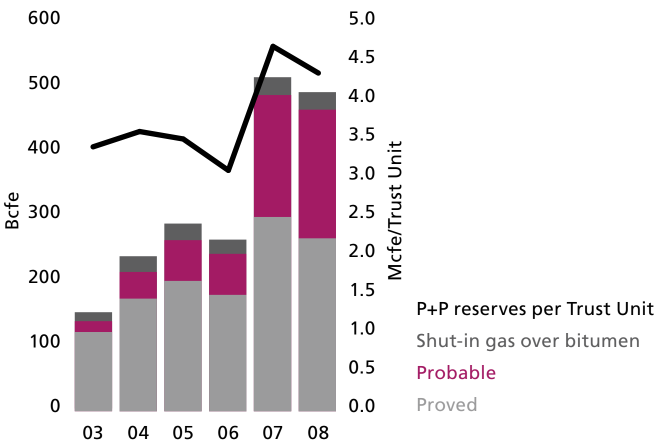
CAPITAL EXPENDITURES



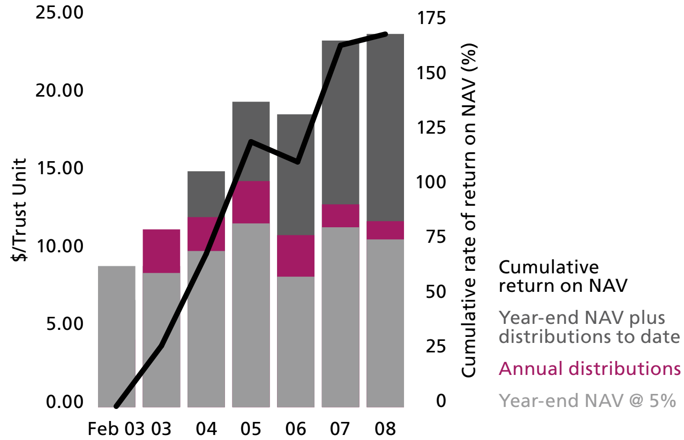
NATURAL GAS PRICES



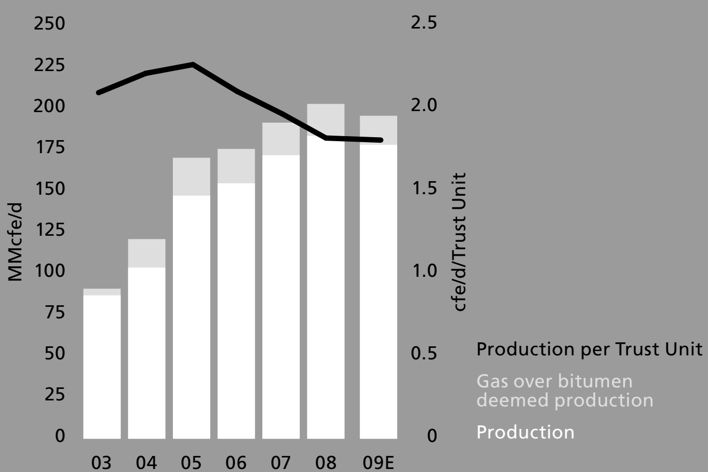
RESERVES
Proved and probable - 487 Bcfe (January 1, 2009)



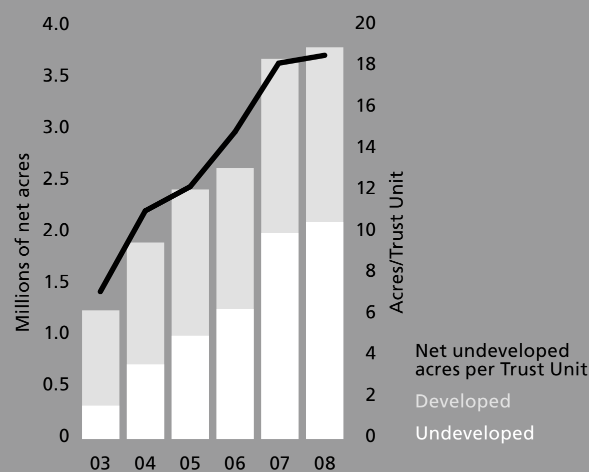
NET ASSET VALUE AND CUMULATIVE DISTRIBUTIONS



PRODUCTION



LAND



Outlook

- PET is nearing completion of a $40 million 2009 winter capital program, drilling 37 gross wells (33.2 net) and executing on the associated completions and tie-ins primarily in its winter only access areas, recompleting approximately 150 net existing wells to activate new zones for production and tying in several late 2008 new drills. Results to-date have been very positive and the Trust expects to add more than 16 MMcfe/d of natural gas production by early April 2009.
- With the current bearish outlook for natural gas prices for the remainder of 2009, the Trust expects to spend only an additional $25 million in the remaining three quarters of 2009, high-grading our drilling activity to those opportunities that are land preserving or strategic in nature. PET is focusing its attention on the capture of prospects for inventory which will be pursued once natural gas prices recover.
- At the current forward strip price for natural gas and including the Trust's 2009 hedges, 2009 distributions, projecting the adjustment to $0.05 per Trust Unit per month beginning in March 2009, represent a payout ratio of 36 percent of forecast 2009 cash flow of $203 million. With forecast capital spending of $65 million, PET's all-in payout ratio is expected to be 68 percent, with excess cash flow of $65 million directed to further reducing bank debt. In this period of global economic uncertainty, the current level of distribution and capital reinvestment will allow PET to maintain its sustainable business model and preserve the strength of the balance sheet in the face of potential additional commodity price weakness.
- Including realized gains on settled financial forward sales contracts of approximately $15 million for the first three months of 2009, the mark-to-market value of the Trust's natural gas forward sales portfolio is currently $170 million. Approximately $85 million is for hedges that will settle post-2009. As the vast majority of the Trust's hedges are financial instruments, this provides the Trust with significant additional financial flexibility in this challenging economic climate.

FINANCIAL AND OPERATING HIGHLIGHTS

($CDN thousands, except volume and per Trust Unit amounts)	Three months ended December 31			Year ended December 31		
	2008	2007	% change	**2008**	2007	% change
FINANCIAL						
Revenue [1][2]	**121,163**	123,747	(2)	**545,701**	462,409	18
Funds flow [2]	**61,513**	59,622	3	**275,434**	239,100	15
Per Trust Unit [2][3]	**0.55**	0.55	-	**2.47**	2.44	1
Cash flow provided by operating activities	**69,179**	38,224	81	**259,764**	222,937	17
Per Trust Unit [3]	**0.61**	0.35	74	**2.33**	2.27	3
Net earnings (loss)	**(8,986)**	(4,970)	81	**30,785**	(32,859)	194
Per Trust Unit [3]	**(0.08)**	(0.05)	60	**0.28**	(0.33)	185
Cash distributions	**33,885**	32,756	3	**133,921**	145,829	(8)
Per Trust Unit [4]	**0.30**	0.30	-	**1.20**	1.50	(20)
Payout ratio (%) [2]	**55.1**	55.0	-	**48.6**	61.0	(20)
Total assets	**1,105,689**	1,212,707	(9)	**1,105,689**	1,212,707	(9)
Net bank and other debt outstanding [2][5]	**284,835**	335,671	(15)	**284,835**	335,671	(15)
Convertible debentures, measured at principal amount	**236,034**	236,109	-	**236,034**	236,109	-
Total net debt [2][5]	**520,869**	571,780	(9)	**520,869**	571,780	(9)
Unitholders' equity	**257,426**	330,935	(22)	**257,426**	330,935	(22)
Capital expenditures						
Exploration and development	**28,329**	20,270	40	**126,091**	117,958	7
Acquisitions, net of dispositions	**(2,143)**	(47,740)	(96)	**(18,514)**	404,168	(105)
Other	**927**	389	138	**1,588**	1,254	27
Net capital expenditures	**27,113**	(27,081)	200	**109,165**	523,380	(79)
TRUST UNITS OUTSTANDING (thousands)						
End of period	**112,968**	109,557	3	**112,968**	109,557	3
Weighted average	**112,865**	109,013	4	**111,473**	98,107	14
Diluted	**112,865**	109,013	4	**112,823**	98,107	15
March 2, 2009	**112,968**			**112,968**		

	Three months ended December 31			Year ended December 31		
	2008	2007	% change	**2008**	2007	% change
OPERATING						
Production						
Total (Bcfe) (6)	**15.9**	17.5	(9)	**66.7**	62.1	7
Average daily (MMcfe/d) (6)	**173.1**	190.3	(9)	**182.2**	170.2	7
Per Trust Unit (cubic feet equivalent/d/ Unit) (3)	**1.53**	1.75	(13)	**1.63**	1.74	(6)
Gas over bitumen deemed production (MMcf/d) (7)	**18.1**	20.0	(10)	**19.2**	19.9	(4)
Average daily (actual and deemed – MMcfe/d) (6) (7)	**191.2**	210.3	(9)	**201.4**	190.1	6
Per Trust Unit (cubic feet equivalent/d/Unit) (3)	**1.69**	1.93	(12)	**1.81**	1.94	(7)
Average natural gas prices ($/Mcfe)						
Before financial hedging and physical forward sales (8)	**6.84**	6.19	11	**8.19**	6.44	27
Including financial hedging and physical forward sales (8)	**7.61**	7.07	8	**8.18**	7.44	10
RESERVES (Bcfe)						
Company interest – proved (9) (10)	**263.6**	294.8	(11)	**263.6**	294.8	(11)
Company interest – proved and probable (9) (10) (11)	**487.1**	509.9	(4)	**487.1**	509.9	(4)
Per Trust Unit (Mcfe/Unit) (12)	**4.31**	4.65	(7)	**4.31**	4.65	(7)
Estimated present value before tax ($ millions) (11)						
Proved	**1,011.4**	972.0	4	**1,011.4**	972.0	4
Proved and probable	**1,642.2**	1,481.0	11	**1,642.2**	1,481.0	11
LAND (thousands of net acres)						
Total land holdings	**3,801**	3,690	3	**3,801**	3,690	3
Undeveloped land holdings	**2,106**	2,001	5	**2,106**	2,001	5
DRILLING (wells drilled gross/net)						
Gas	**24/23.6**	23/18.3	4/29	**91/75.4**	129/103.2	(29)/(27)
Dry	**-/-**	1/1.0	(100)/(100)	**2/1.6**	8/7.2	(75)/(78)
Total	**24/23.6**	24/19.3	-/22	**93/77.0**	137/110.4	(32)/(30)
Success rate	**100/100**	96/95	4/5	**98/98**	94/93	4/5

(1) Revenue includes realized gains and losses on financial instruments and call option premiums received.

(2) This is a non-GAAP measure; please refer to "Significant accounting policies and non-GAAP measures" included in Management's Discussion and Analysis.

(3) Based on weighted average Trust Units outstanding for the period.

(4) Based on Trust Units outstanding at each cash distribution date.

(5) Net debt is measured as at the end of the period and includes net working capital (deficiency), excluding short-term financial instrument assets and liabilities related to the Trust's hedging activities and the current portion of convertible debentures. Total net debt includes convertible debentures.

(6) Production amounts are based on the Trust's interest before deduction of royalties.

(7) Deemed production describes all gas shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the Alberta Energy and Utilities Board ("AEUB"), or through correspondence in relation to an AEUB ID 99-1 application. This deemed production is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution received monthly from the Alberta Crown as a reduction of other royalties payable.

(8) PET's commodity hedging strategy employs both financial forward contracts and physical natural gas delivery contracts at fixed prices or price collars. In calculating the Trust's natural gas price before financial and physical hedging, PET assumes all natural gas sales based on physical delivery fixed-price or price collar contracts during the period were instead sold at AECO monthly index.

(9) As evaluated by McDaniel & Associates Consultants Ltd. in accordance with National Instrument 51-101. See "Reserves" included in Management's Discussion and Analysis.

(10) Reserves are presented on a company interest basis, including working interest and royalty interest volumes but before royalty burdens. Royalty interest volumes totaled 3.3 Bcfe on a proved and probable basis in 2008 (2007 – 4.7 Bcfe).

(11) Discounted at five percent using consultant's forecast pricing. Reserves at various other discount rates are located in the "Reserves" section of Management's Discussion and Analysis. Includes gas over bitumen royalty adjustments (2008 – $70.5 million, 2007 – $77.5 million) related to the financial solution described in Note 7 above and estimated probable gas over bitumen shut-in reserves (2008 – 26.6 Bcf and $78.3 million, 2007 – 27.3 Bcf and $68.7 million). Estimated present value amounts should not be taken to represent an estimate of fair market value.

(12) Based on Trust Units outstanding at period end.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Paramount Energy Trust's ("PET" or the "Trust") operating and financial results for the year ended December 31, 2008 as well as information and estimates concerning the Trust's future outlook based on currently available information. This discussion should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2008 and 2007, together with accompanying notes. Readers are referred to the legal advisories regarding forward-looking information contained in the "Forward Looking Information" section of this MD&A. The date of this MD&A is March 6, 2009.

Mcf equivalent (Mcfe) and barrel of oil equivalent (boe) may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), a conversion ratio for Mcfe and boe 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.

SIGNIFICANT ACCOUNTING POLICIES AND NON-GAAP MEASURES

Successful efforts accounting

The Trust follows the successful efforts method of accounting for its petroleum and natural gas operations. This method differs from the full cost accounting method in that exploration expenditures, including exploratory dry hole costs, geological and geophysical costs, lease rentals on undeveloped properties as well as the cost of surrendered leases are expensed rather than capitalized in the year incurred. However, to allow reported funds flow in this MD&A to be comparable to industry practice, the Trust reclassifies geological and geophysical costs as well as surrendered leases and abandonment costs from operating to investing activities in the funds flow reconciliation.

Funds flow

Management uses funds flow from operations before changes in non-cash working capital, asset retirement expenditures and certain exploration costs ("funds flow"), funds flow per Trust Unit and annualized funds flow to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore it may not be comparable to the calculation of similar measures for other entities. 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 provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Funds flow is reconciled to its closest GAAP measure, cash flow provided by operating activities, as follows:

Funds flow GAAP reconciliation	For the three months ended December 31		For the year ended December 31	
($ thousands, except per Trust Unit amounts)	**2008**	2007	**2008**	2007
Cash flow provided by operating activities	**69,179**	38,224	**259,764**	222,937
Exploration costs (1)	**3,820**	2,120	**9,178**	11,034
Settlement of asset retirement obligations	**1,636**	314	**5,226**	2,597
Changes in non-cash operating working capital	**(13,122)**	18,964	**1,266**	2,532
Funds flow	**61,513**	59,622	**275,434**	239,100
Funds flow per Trust Unit (2)	**0.55**	0.55	**2.47**	2.44

(1) Certain exploration costs are added to funds flow in order to be more comparable to other energy trusts that use the full cost method of accounting for oil and gas activities. Exploration costs that are added to funds flow include seismic expenditures and dry hole costs and are considered by PET to be more closely related to investing activities than operating activities.

(2) Based on weighted average Trust Units outstanding for the period.

Additional significant accounting policies and non-GAAP measures are discussed elsewhere in this MD&A.

DISCLOSURE CONTROLS AND PROCEDURES

Disclosure controls and procedures have been designed to ensure that information required to be disclosed by the Trust is accumulated and communicated to the Trust's management, as appropriate, to allow timely decisions regarding required disclosure. The Trust's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of December 31, 2008 (the "Evaluation Date"), that the Trust's disclosure controls and procedures as of the Evaluation Date are effective to provide reasonable assurance that material information related to the Trust, including its consolidated subsidiaries, is made known to them by others within those entities.

INTERNAL CONTROLS OVER FINANCIAL REPORTING

Internal controls have been designed to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements together with the other financial information for external purposes in accordance with GAAP. The Trust's Chief Executive Officer and Chief Financial Officer have designed or caused to be designed under their supervision internal controls over financial reporting related to the Trust, including its consolidated subsidiaries.

The Trust's Chief Executive Officer and Chief Financial Officer are required to cause the Trust to disclose herein any change in the Trust's internal control over financial reporting that occurred during the Trust's most recent interim period that materially affected, or is reasonably likely to materially affect the Trust's internal control over financial reporting. During 2008, the Trust engaged external consultants to assist in assessing the Trust's design of internal controls over financial reporting. No material changes were identified in the Trust's internal control of financial reporting during the year ended December 31, 2008, that had materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

Management will complete certifications in accordance with Section 404 of the Sarbanes-Oxley Act, which will be included in PET's form 40-F filed on EDGAR in the United States.

It should be noted that a control system, including the Trust's disclosure and internal controls and procedures, no matter how well conceived can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

CHANGES TO INTERNAL CONTROLS AND PROCEDURES FOR FINANCIAL REPORTING

There were no significant changes to PET's internal controls or other factors that could significantly affect these controls subsequent to the Evaluation Date.

CORPORATE GOVERNANCE

PET is committed to maintaining high standards of corporate governance. Each regulatory body, including the Toronto Stock Exchange, the Canadian provincial securities commissions and the Securities and Exchange Commission (whose responsibilities include implementing rules under the United States Sarbanes-Oxley Act of 2002) has a different set of rules pertaining to corporate governance. PET fully conforms to the rules of the governing bodies under which it operates and, in many cases, already complies with proposals and recommendations that have not come into force.

GLOBAL ECONOMIC ENVIRONMENT

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 in world financial markets. 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 and the widening of credit spreads. Another result of these events is a significant drop in current and forward prices for crude oil and natural gas from the highs reached in mid-2008.

Despite adverse economic conditions, PET's operations and business philosophy have not changed per se, although the Trust has significantly increased our attention to aggressively manage the Trust's healthy balance sheet and increased our downside protection against falling natural gas prices in these uncertain times. The Trust continues to adhere to its four-pronged business plan:

- Maximize cash flow from operations –The Trust's gas hedging portfolio contributed $14.9 million of additional funds flow to PET in the first three months of 2009, and PET has 100.3 MMcfe/d of natural gas production hedged for April to December 2009 at an average price of $7.74 per Mcfe. Further price management is in place to the end of March 2011 with an average 96.7 MMcf/d hedged at $8.09 per Mcfe.
- Asset optimization – Revised capital spending plans for 2009 of $65 million are directed towards low-risk, low-cost projects, aimed at limiting natural production declines on PET's assets to three percent year over year.
- Accretive acquisitions – PET disposed of several non-core assets in 2008 for proceeds of $24.2 million. In addition, a public marketing process is currently underway for four additional properties although it is unclear if PET will receive acceptable offers at this time. PET completed a small acquisition synergistic to several of the Trust's properties in January 2009 for $7.5 million, and will look for additional accretive acquisitions during the current down cycle for natural gas as opportunities arise.
- Healthy balance sheet – The Trust reduced net debt by $51 million during 2008, and adjusted distributions and capital spending plans in 2009 in order to preserve sustainability in this uncertain economic environment.

The Trust has met several significant challenges in its history, including the gas over bitumen shut-in hearings, the federal trust tax legislation and the new royalty regime, and has persevered despite these obstacles. All four components of the Trust's business plan combine to result in an overall focus on maximizing Unitholder value, and PET's technical and administrative staff are dedicated to this objective, both navigating the challenges and taking advantage of the opportunities presented by the changes in the surrounding business environment.

FOURTH QUARTER 2008 RESULTS

- Production decreased nine percent to average 173.1 MMcfe/d as compared to 190.3 MMcfe/d for the fourth quarter of 2007, as lower production due to asset dispositions, cold-weather related downtime and natural production declines in the Northern district and delays in bringing on new production in the Southern district due to third party-operated facility constraints was partially offset by new production additions from the Trust's 2008 capital programs.
- The Trust's realized natural gas price increased to $7.61 per Mcfe for the three months ended December 31, 2008 from $7.07 per Mcfe for the three months ended December 31, 2007, consistent with the increase in AECO gas prices from quarter to quarter.
- Funds flow totaled $61.5 million for the quarter or $0.55 per Trust Unit as compared to $59.6 million or $0.55 per Trust Unit in the fourth quarter of 2007, due to higher realized natural gas prices in the current quarter partially offset by a decrease in production volumes.
- Capital spending totaled $27.1 million for the fourth quarter, including the drilling of 24 wells (23.6 net wells) primarily in the Southern district with a 100 percent success rate. The majority of these wells are expected to come onstream in the first quarter of 2009 after tie-ins are complete.
- Distributions for the fourth quarter of 2008 totaled $0.30 per Trust Unit, paid on November 17, 2008, December 15, 2008 and January 15, 2009. PET's payout ratio, which refers to distributions measured as a percentage of funds flow, was 55.1 percent for the quarter.
- PET finished planning and began the execution of a $40 million 2009 winter capital program targeting 15 to 20 MMcfe/d of natural gas production additions through drilling, completion, tie-in and facility projects primarily in the Trust's three core areas in northeast Alberta.

ANNUAL RESULTS

($ millions, except volumes and per Trust Unit amounts)	**2008**	2007	2006
Cash flow provided by operating activities	**259.8**	222.9	228.6
Cash flow provided by operating activities per Trust Unit	**2.33**	2.27	2.72
Funds flow (1)	**275.4**	239.1	236.7
Funds flow per Trust Unit (1)	**2.47**	2.44	2.82
Net earnings (loss)	**30.8**	(32.9)	(18.9)
Distributions	**133.9**	145.8	221.8
Distributions per Trust Unit	**1.20**	1.50	2.64
Payout ratio (%) (1)	**48.6**	61.0	93.7
Net bank and other debt outstanding at December 31 (2)	**284.9**	335.7	245.5
Convertible debentures, measured at principal amount	**236.0**	236.1	161.1
Total net debt at December 31 (2)	**520.9**	571.8	406.6
Total net debt per Trust Unit (2) (4)	**4.61**	5.22	4.77
Production (MMcfe/d) (3)			
Daily average production	**182.2**	170.2	153.4
Gas over bitumen deemed production	**19.2**	19.9	20.8
Total average daily (actual and deemed)	**201.4**	190.1	174.2
Production per Trust Unit (cubic feet equivalent/d/Unit)	**1.63**	1.74	1.83
Production per Trust Unit – actual and deemed (cubic feet equivalent/d/Unit)	**1.81**	1.94	2.08

(1) These are non-GAAP measures; please refer to "Significant Accounting Policies and Non-GAAP measures" included in this MD&A.

(2) Net debt is measured as at the end of the period and includes net working capital (deficiency) excluding short-term financial instrument assets and liabilities related to the Trust's hedging activities and the current portion of convertible debentures. Total net debt includes convertible debentures. Please refer to "Significant accounting policies and non-GAAP measures" included in this MD&A.

(3) Production amounts are based on company interest (working interest and royalties receivable) before royalties payable.

(4) Based on Trust Units outstanding at period end.

- Daily average production increased seven percent to a record 182.2 MMcfe/d in 2008 as a result of a full year of production from the acquisition of predominantly natural gas producing properties in east central Alberta ("the Birchwavy Acquisition") in June 2007 and successful capital programs during the year.
- Funds flow increased 15 percent to a record $275.4 million or $2.47 per Trust Unit in 2008 as compared to $239.1 million or $2.44 per Trust Unit for 2007 due primarily to increased production levels and higher realized natural gas prices, partially offset by higher royalties and operating expenses.
- Exploration and development capital spending totaled $126.1 million in 2008, comprised of a $45.8 million winter capital program focused on activities in the Trust's three core areas in northeast Alberta with the remaining capital expenditures directed primarily towards PET's expanding year-round access asset base in east central Alberta. In total 93 wells were drilled (77.0 net) with a 98 percent success rate. Capital spending for 2008 included the acquisition of several parcels of exploratory acreage totaling 78 net sections in west central Alberta for $19.1 million. This new venture area offers exposure to several high impact natural gas deep basin resource plays to complement PET's primarily low risk shallow gas prospect inventory.
- In 2008, the Trust added 35.5 Bcfe of proved reserves and 8.3 Bcfe of probable reserves for total reserve additions of 43.8 Bcfe of proved and probable reserves, excluding production. After production of 66.7 Bcfe in 2008, proved and probable reserves decreased four percent from 509.9 Bcfe at year end 2007 to 487.1 Bcfe and proved reserves decreased 11 percent to 263.6 Bcfe at year end 2008. Reserve additions largely offsetting production were due to the successful reinvestment of $126.1 million in exploration and development spending programs, representing approximately 46 percent of the Trust's 2008 funds flow.
- PET's total capital expenditures including acquisitions net of dispositions but excluding corporate asset additions were $107.6 million for 2008. Including future development capital and an additional $6.8 million recorded in 2009 for an acquisition which closed in January 2009 but for which reserves were booked in 2008, PET realized top-quartile finding, development and acquisition costs of $2.62 per Mcfe ($15.72 per boe) for proved reserves and $2.52 per Mcfe ($15.12 per boe) for proved and probable reserves in 2008. Excluding the acquisition of prospective acreage in west central Alberta for $19.1 million, for which PET did not undertake any reserve-adding activity in 2008, finding, development and acquisition costs for the year totaled $2.08 per Mcfe ($12.48 per boe) for proved reserves and $2.08 per Mcfe ($12.48 per boe) for proved and probable reserves.
- PET's average realized gas price was $8.18 per Mcfe in 2008, a ten percent increase from $7.44 per Mcfe in 2007. The Trust continued to execute on its proactive natural gas price risk management strategy in 2008, providing a measure of stability to realized prices and cash flows despite significant volatility in natural gas prices. For April through December 2009 PET has an average of 57 percent of estimated natural gas production hedged at an average price of $7.74 per Mcf. The current April to December 2009 forward monthly market for natural gas at AECO at the date of this MD&A is $4.78 per Mcf. Further price management contracts are in place through March 2011. The total mark-to-market value of PET's financial instruments as of March 9, 2009 is approximately $154 million.
- As a result of funds flows in excess of distributions and capital expenditures and minor non-core property dispositions, PET reduced net bank debt by 15 percent from $335.7 million at December 31, 2007 to $284.8 million drawn on its $410 million bank facility at December 31, 2008. Including PET's convertible debentures of $236.1 million, total net debt dropped from $571.8 million at December 31, 2007 to $520.9 million at December 31, 2008. The Trust lowered its total net debt to annualized quarterly funds flow ratio from 2.4 to 2.1 during the year.

OPERATIONS

Properties

PET expanded the geographic boundaries of its operations with the Birchwavy Acquisition in June 2007. At the same time, the key attributes of PET's asset base remained unchanged. The Trust's assets are focused geographically in northeast and east central Alberta and technically with shallow natural gas comprising 98 percent of production volumes and reserves. The vast majority of PET's properties feature well established, high working interest production and most are operated by PET. The Trust's production profile is predictable due to the lengthy production histories and the large number of independent producing entities in PET's asset base. The large number of wells and facilities means unexpected downtime at any single site does not have a material impact on overall production. Competitive operating costs and access to markets proximal to the producing properties combine to deliver high field netbacks. PET has an extensive inventory of low cost opportunities for value creation which extends throughout the asset base and the Trust has a history of adding production through relatively modest capital expenditures to offset most of the annual natural production declines. Strategic infrastructure ownership throughout PET's asset base provides additional opportunities to add value through synergies and economies of scale.

Northern district

The Northern district is comprised of PET's legacy gas producing assets transferred with its spin out from Paramount Resources in 2003 and has been complemented with consolidating and operationally synergistic asset acquisitions. Generally access for capital activities is restricted to winter-only. This Northern District largely overlaps the Athabasca Oil Sands area and the Trust has acquired a material inventory of oil sands leases for future development using a variety of subsurface recovery technologies.

West Side - Significant areas of production in this core area west of Alberta Highway 63 include Ells, Legend/East Legend, Liege, Saleski, Teepee Creek and Woodenhouse. Production is primarily from the Devonian Grosmont and overlying Cretaceous McMurray and Wabiskaw formations. The Trust has bitumen leases in this area at South Liege and Saleski.

East Side - Thornbury, Craigend, Corner, Leismer, Chard, Kettle, Quigley and Cold Lake are the major producing properties operated by PET in this operating core area east of Alberta Highway 63. Production is mainly from Cretaceous Clearwater and Grand Rapids/Colony reservoirs. The majority of the shut-in gas related to the gas over bitumen issue is in the Wabiskaw-McMurray formation in this area. In addition the Trust has a small bitumen land position at Clyde.

Athabasca - Athabasca is Paramount Energy Trust's largest producing core area and includes assets south and west of the Trust's original spin-out assets in the West Side area. Production is from multiple stratigraphic horizons including Cretaceous clastic and Devonian carbonate reservoirs. Significant gas producing properties in this core operating area include Calling Lake, Darwin, Marten Hills, Mitsue, Panny, Peter Lake and Wabasca/Hoole. PET owns oil sands leases at Panny, Wabasca Lake and Marten Hills.

Southern district

Natural gas in the Southern district is from a base of varied assets with characteristics similar to the Northern district assets, but with the added advantage of having year-round access. Production in this multi-zoned potential area is from over 10 different Cretaceous or Devonian aged reservoirs and consists of both conventional and tight unconventional shall gas reservoirs.

Birchwavy West - Operations in Birchwavy West consist of conventional and tight, unconventional, shallow natural gas assets in the Warwick, Bruce and Killam areas of central Alberta are the major producing properties in this core area. A significant inventory of proved undeveloped reserves is present in this area targeting a resource-style play in the Viking formation.

Birchwavy East - Production from the Birchwavy East area is primarily from Colony channel reservoirs in the Cretaceous Mannville zone as well as other conventional Mannville sand reservoirs. In addition unconventional, tight, shallow gas resource play potential from the Viking formation extends across these assets. It includes the largest properties in the area, Mannville and Duvernay.

East Central - East Central Alberta is separated from the Birchwavy areas by the North Saskatchewan River. Production from these assets is from conventional Devonian and Cretaceous Mannville targets and is generally processed through third party facilities.

Severo Energy Corporation

In 2006, to facilitate development of minor assets in the Athabasca core area, Paramount Energy Trust transferred certain assets in the Radway /Abee area to a new private company, Severo Energy Corporation ("Severo"). Paramount Energy Trust has an indirect ownership of 93 percent in Severo. Production in Severo's core area is primarily derived from the Second White Specks, Colony, Viking, Glauconite, Ellerslie and Wabamum formations. Severo's business strategy concentrates on continued growth in the core area of Big Bend/Radway through re-completions, low risk drills and synergistic consolidating acquisitions.

Production

Natural gas production by core area (MMcfe/d)	**2008**	2007	2006
Northern district			
West Side	**37.2**	42.5	46.3
East Side	**27.6**	27.0	26.4
Athabasca	**52.5**	56.8	68.0
Northern district total	**117.3**	126.3	140.7
Southern district			
Birchwavy West (1)	**22.6**	12.4	-
Birchwavy East (1)	**29.5**	18.7	-
East Central (1) (2)	**4.1**	2.7	7.0
Southern district total	**56.2**	33.8	7.0
Severo	**7.0**	6.3	1.0
Other	**1.7**	3.8	4.7
Total	**182.2**	170.2	153.4
Deemed production (3)	**19.2**	19.9	20.8
Total actual plus deemed production	**201.4**	190.1	174.2

(1) 2007 amounts include contribution to annual average from these areas. Production from the date of the Birchwavy Acquisition of June 26, 2007 to December 31, 2007 was 21.5 MMcfe/d, 32.2 MMcfe/d, and 3.1 MMcfe/d for Birchwavy West, Birchwavy East and East Central, respectively.

(2) In 2006, the East Central core area included certain assets that were reallocated to the Birchwavy West and East core areas to more closely align with the Trust's expanded operations in the region.

(3) Deemed production is a result of shut-in production volumes in the East Side core area. See "Gas over bitumen royalty adjustments" in this MD&A.

Production volumes increased seven percent to 182.2 MMcfe/d in 2008 from 170.2 MMcfe/d in 2007. The increase is primarily due to the full year effect of production from the Birchwavy Acquisition and a successful 2008 winter capital program which partially offset production declines in each of the three core areas in the Northern district. The increase in production in the Southern district is due to the Birchwavy Acquisition completed in June 2007 and continuing development of the Trust's shallow gas assets in east central Alberta.

In 2008, the five largest properties located within the Trust's core areas accounted for 32 percent of the Trust's production with the largest single property, Wabasca in the Athabasca core area, accounting for seven percent of the total production. By comparison, in 2007 the five largest properties represented 33 percent of PET's total production with Wabasca representing eight percent. This diversification of production minimizes the risk that operating problems at a specific property will materially impact the Trust.

Capital expenditures

Capital expenditures ($ thousands)	**2008**	2007	2006
Exploration and development expenditures (1)	**99,512**	109,933	125,638
Crown and freehold land purchases	**26,579**	8,025	12,621
Acquisitions	**5,706**	450,576	97,449
Dispositions	**(24,220)**	(46,408)	(17,689)
Other	**1,588**	1,254	1,267
Total capital expenditures	**109,165**	523,380	219,286

(1) 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 (2007 – $11.0 million). Exploration costs include seismic expenditures and dry hole costs which 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 expenditures in 2008 do not include $9.5 million in lease expiries or $12.0 million in undeveloped land impairment charges recorded in the current year.

Exploration and development expenditures measured $99.5 million in 2008 as compared to $109.9 million for 2007. PET completed a successful winter capital program in northeast Alberta in the first quarter of 2008, investing $45.8 million in new drilling, recompletion, workover and facilities optimization work primarily in the Trust's winter-access only core areas in northeast Alberta. Capital expenditures for the remaining three quarters were concentrated on properties in the Southern district and all-season access opportunities at East Side in the Northern district. Acquisitions and ongoing exploration activities in east central Alberta have provided PET with a multi-year drilling inventory of low-risk shallow gas targets on all-weather access properties, which has enabled the Trust to spread its capital programs evenly throughout the year, as opposed to the highly concentrated winter month spending profile that characterized the Trust's annual capital spending programs in the early years after PET's spinout in 2003.

Land acquisitions totaled $26.6 million in 2008, an $18.6 million increase from 2007 levels. Current year expenditures include the acquisition of several large parcels of exploratory acreage in west central Alberta for $19.1 million, and approximately $3.1 million of oil sands leases primarily in the Athabasca core area. West central Alberta is a new venture area for the Trust and offers exposure to several high impact deep basin resource plays to counterbalance the low exposure shallow gas exploration opportunities characteristic of PET's traditional prospect inventory.

Dispositions totaled $24.2 million in 2008 compared to $46.4 million in 2007. Properties sold in 2008 were primarily non-core assets and royalty interests in central and southern Alberta and Saskatchewan. 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. Dispositions in 2007 included the sale of the Trust's downtown Calgary office building for gross proceeds of $35.7 million.

The Board of Directors of Paramount Energy Operating Corp., PET's Administrator, has approved a further revised capital expenditure budget of $65 million for 2009, including crown and freehold land purchases. A $40 million winter capital program is largely complete while capital expenditures for the remainder of the year can be adjusted depending on natural gas prices, as deemed appropriate.

Drilling

		2008		2007		2006
Wells drilled	**Gross**	**Net**	Gross	Net	Gross	Net
Gas	**91**	**75.4**	129	103.2	148	111.8
Dry	**2**	**1.6**	8	7.2	4	1.9
Total	**93**	**77.0**	137	110.4	152	113.7
Success rate (%)	**98**	**98**	94	93	97	98

PET drilled 77.0 net wells in 2008 as compared to 110.4 wells in 2007. Drilling activity in 2008 included 30 (22.1 net) wells spread throughout the Trust's three core areas in the Northern district, achieving a 100 percent net success rate, and 49 wells (45.2 net) in the Southern district with a 98 percent net success rate. Severo drilled a total of 14 wells (9.7 net) in 2008, experiencing a 94 percent net success rate.

Reserves

PET's complete National Instrument 51-101 reserves disclosure as at December 31, 2008 including underlying assumptions regarding commodity prices, expenses and other factors, and reconciliation of reserves on a net interest basis (working interest less royalties payable) is contained in the Trust's Annual Information Form for the year ended December 31, 2008.

The reserves data set out below (the "Reserves Data") is wholly based upon an evaluation by McDaniel and Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2008 contained in a report of McDaniel dated January 31, 2009 (the "McDaniel Report"). McDaniel's evaluation covers 100 percent of the Trust's oil and natural gas properties and reserves. The Reserves Data summarizes the oil, liquids and natural gas reserves of the Trust and the net present values of future net revenue for these reserves using McDaniel forecast prices and costs. As 98 percent of the Trust's reserves are natural gas, volumes are presented on an Mcf equivalent basis. PET reports the results of the Trust's 93 percent-owned subsidiary Severo Energy Corp. ("Severo") using consolidation accounting, and therefore the amounts shown include 100 percent of the volumes and net present values related to the reserves of Severo. Reserves are presented on a company interest basis, including royalty interests and before royalty burdens. Columns and rows in reserve and net present value tables may not add due to rounding.

Natural gas reserves as at December 31 (MMcfe)	**2008**	2007	2006
Proved			
Developed producing	**210,855**	231,339	163,363
Developed non-producing	**13,621**	16,598	7,072
Undeveloped	**39,138**	46,843	6,703
Total proved	**263,615**	294,780	177,139
Probable producing, non-producing and undeveloped	**196,793**	187,818	62,717
Shut-in gas over bitumen (1)	**26,648**	27,308	21,644
Total probable	**223,441**	215,126	84,361
Total proved & probable	**487,055**	509,907	261,500
Trust Units outstanding (millions)	**113.0**	109.6	85.2
Total proved & probable per Trust Unit (Mcfe/Unit)	**4.31**	4.65	3.07

(1) The McDaniel report assumes that the shut-in gas over bitumen reserves are probable but the future abandonment and reclamation liability associated with the wells is proved, that the reserves return to production after ten years of shut-in and that such production is subject to an incremental ten percent gross overriding royalty pursuant to the amended Royalty Regulation.

The net present values of future net revenues ("NPV") for PET's reserves, before taxes using McDaniel forecast prices and costs at zero, five and ten percent discount rates are presented in the table below.

NPV of reserves at December 31 ($ millions)	**0%**	**5%**	**2008** **10%**	0%	5%	2007 10%	0%	5%	2006 10%
Proved									
Developed producing	**1,008.7**	**845.7**	**739.2**	967.5	806.0	704.1	666.3	591.8	533.7
Developed non-producing (1)	**9.8**	**14.2**	**14.8**	(0.4)	9.4	11.4	(11.6)	(9.3)	(7.7)
Gas over bitumen royalty adjustments	**79.6**	**70.5**	**63.2**	88.9	77.5	68.5	103.1	88.1	76.6
Undeveloped	**112.5**	**81.0**	**58.8**	114.0	79.1	55.1	6.7	4.6	2.8
Total proved	**1,210.6**	**1,011.4**	**876.0**	1,170.0	972.0	839.1	764.5	675.2	605.4
Probable									
Developed and undeveloped	**797.4**	**552.5**	**405.9**	655.2	440.3	317.5	275.4	213.4	171.5
Shut-in gas over bitumen reserves (2)	**123.1**	**78.3**	**51.7**	112.3	68.7	44.4	88.5	53.9	34.1
Total probable	**920.5**	**630.8**	**457.6**	767.5	509.0	361.9	363.9	267.3	205.6
Total proved & probable	**2,131.1**	**1,642.2**	**1,333.6**	1,937.5	1,481.0	1,201.0	1,128.4	942.5	811.0
Trust Units outstanding (millions)	**113.0**	**113.0**	**113.0**	109.6	109.6	109.6	85.2	85.2	85.2
Total proved & probable per Trust Unit ($/Unit)	**18.86**	**14.53**	**11.80**	17.68	13.51	10.96	13.24	11.06	9.52

(1) The McDaniel Report incorporates an estimate for abandonment costs for producing and non-producing wells. This may result in a net liability to PET for wells in this category.

(2) The McDaniel report assumes that the shut-in gas over bitumen reserves are probable but the future abandonment and reclamation liability associated with the wells is proved, that the reserves return to production after ten years of shut-in and that such production is subject to an incremental ten percent gross overriding royalty pursuant to the amended Royalty Regulation.

At a ten percent discount factor, the proved producing reserves including gas over bitumen royalty adjustments comprise 60 percent of the proved and probable value while total proved reserves account for 66 percent of the proved and probable value at December 31, 2008.

With the enactment of trust tax legislation (see "Income Taxes") PET is now required to present the net present values of future net revenue on an after-tax basis. The after-tax amounts from the McDaniel report using forecast prices and costs are shown below.

After-tax net present values as at December 31, 2008 ($ millions, discounted at 0% and 10%)	Total Proved 0%	Total Proved 10%	Total Proved and Probable 0%	Total Proved and Probable 10%
Net present value, before taxes	1,210.6	876.0	2,131.1	1,333.6
Income taxes	(100.5)	(67.0)	(304.4)	(170.4)
Net present value, after taxes	1,110.1	809.0	1,826.7	1,163.2

The McDaniel Report assumes the utilization of PET's current existing tax pools plus additions from future development costs, beginning in 2009 with taxation of after-tax cash flow at corporate income tax rates beginning in 2011. Actual future results will differ materially from the assumptions mandated by National Instrument 51-101, as the Trust has an extensive prospect inventory beyond the future development projects recognized by the McDaniel Report. These include additional recompletions in existing wellbores, drilling prospects and infrastructure projects.

The following table sets forth a reconciliation of the changes in reserves for the year ended December 31, 2008 from the opening balance on December 31, 2007 derived from the McDaniel Reports at those dates, using McDaniel forecast prices.

Reserves reconciliation (Bcfe)	Proved	Probable	Proved & Probable
December 31, 2007	294.8	215.1	509.9
Discoveries and extensions	21.9	18.0	39.9
Technical revisions	11.0	(11.4)	(0.4)
Acquisitions, net of dispositions	0.3	(0.4)	(0.1)
Production	(66.7)	-	(66.7)
Economic factors	2.4	2.1	4.5
December 31, 2008	**263.7**	**223.4**	**487.1**

Finding, development and acquisition costs

Under NI 51-101, the methodology to be used to calculate finding, development and acquisition ("FD&A") costs includes incorporating changes in future development capital ("FDC") required to bring the proved undeveloped and probable reserves to production. Changes in forecast FDC occur annually as a result of development activities, acquisitions and disposition activities and capital cost estimates. For continuity, PET has presented herein FD&A costs calculated both excluding and including FDC.

FD&A costs – company interest reserves ($ millions except where noted)	Proved	Proved excluding pure exploration(2)	Proved and Probable	Proved and Probable excluding pure exploration(2)
FD&A costs excluding future development capital				
Exploration and development capital expenditures	$ 126.1	$ 107.0	$ 126.1	$ 107.0
Dispositions, net of acquisitions	(18.5)	(18.5)	(18.5)	(18.5)
	$ 107.6	$ 88.5	$ 107.6	$ 88.5
Acquisition closed in 2009 (1)	6.8	6.8	6.8	6.8
FD&A capital expenditures	$ 114.4	$ 95.3	$ 114.4	$ 95.3
Reserve additions including net acquisitions (Bcfe)	35.5	35.5	43.8	43.8
Finding, development and acquisition cost ($/Mcfe)	$ 3.22	$ 2.68	$ 2.61	$ 2.18
FD&A costs including future development capital				
FD&A capital expenditures	$ 114.4	$ 95.3	$ 114.4	$ 95.3
Total change in FDC	(21.4)	(21.4)	(4.1)	(4.1)
Total FD&A capital including change in FDC	$ 93.0	$ 73.9	$ 110.3	$ 91.2
Reserve additions including net acquisitions (Bcfe)	35.5	35.5	43.8	43.8
Finding development and acquisition cost including FDC - $/Mcfe	$ 2.62	$ 2.08	$ 2.52	$ 2.08

(1) The McDaniel Report includes the reserves related to an acquisition which closed in January 2009. As the related capital expenditures will not be recorded for accounting purposes until 2009, they have been added to FD&A capital expenditures.

(2) Capital expenditures for pure exploration crown land expenditures in west central Alberta where no reserve-adding activities were conducted in 2008 of $19.1 million have been excluded.

Effect of new Alberta royalty regime

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 will 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.

Land

Land inventory	2008 Net acres	2008 Average working interest (%)	2007 Net acres	2007 Average working interest (%)	2006 Net acres	2006 Average working interest (%)
Developed	**1,694,944**	**65.9**	1,689,182	65.4	1,364,086	69.5
Undeveloped	**2,106,021**	**81.1**	2,000,768	80.3	1,272,813	79.8
Total	**3,800,965**	**73.6**	3,689,950	72.8	2,636,899	74.2

PET's undeveloped acreage position increased by five percent in 2008, as a result of the acquisition of 132,000 net acres of oil sands leases and 50,000 net acres in west central Alberta, as well as ongoing crown land purchases to capture shallow gas exploration opportunities in the Trust's core areas, partially offset by lease expiries in 2008. PET has one of the most extensive inventories of undeveloped land in the energy trust sector relative to its production and reserves base.

The Trust's undeveloped acreage in the East Side core area includes approximately 271,000 net acres inside the gas over bitumen area of concern. While development of this acreage is restricted in certain formations, there are numerous other prospective zones in the region. The mineral rights for leases with shut-in production are continued indefinitely under Section 8-1-h of the Mines and Minerals Act (Alberta) until resolution of the gas over bitumen issue. The Trust now has in inventory a total of 420,000 net acres of oil sands leases.

The fair market value of PET's undeveloped acreage is estimated to be $141 million at December 31, 2008 (December 31, 2007 - $151 million), using a combination of average land sale values by area and the cost of recent land purchases by the Trust. Land sale prices in the Trust's core areas have dropped approximately 38 percent on average in 2008 relative to 2007 as a result of the new Alberta royalty regime and other economic factors.

Net asset value

The following net asset value ("NAV") table shows what is normally referred to as a "produce-out" NAV calculation under which the Trust's reserves would be produced at forecast future prices and costs. The value is a snapshot in time and is based on various assumptions including commodity prices and foreign exchange rates that vary over time. It should not be assumed that the NAV represents the fair market value of PET Units. The calculations below do not reflect the Trust's current financial forward natural gas contracts or the value of the Trust's extensive prospect inventory to the extent that the prospects are not recognized within the NI-51-101 compliant reserve assessment. The value of PET's prospect inventory is captured only through the assessment of the fair market value of undeveloped land based on current land sale valuation parameters which declined $9.6 million year over year with the general reduction in land sale prices in Alberta in 2008. PET's internal estimate of the risk-discounted future value of captured prospects significantly exceeds the estimated fair market value of undeveloped land. PET runs its business on a going-concern basis, investing in opportunities to add reserves, production and cash flow, improve profitability and add value which enhance the Trust's NAV beyond the amounts shown in its annual reserve evaluation.

Pre-tax net asset value at December 31, 2008 (1) ($ millions except where noted)	Undiscounted	5%	8%	Discounted at 10%
Total proved and probable reserves (2)	2,131.1	1,642.2	1,442.2	1,333.6
Fair market value of undeveloped land (3)	141.1	141.1	141.1	141.1
Net bank debt	(284.8)	(284.8)	(284.8)	(284.8)
Convertible debentures	(236.0)	(236.0)	(236.0)	(236.0)
Estimate of additional future abandonment and reclamation costs (4)	(80.7)	(61.6)	(52.5)	(47.5)
Net asset value	1,670.7	1,200.9	1,010.0	906.4
Trust Units outstanding (million)	113.0	113.0	113.0	113.0
Net asset value per Trust Unit ($/Unit)	14.78	10.63	8.94	8.02

(1) Financial information is per PET's 2008 consolidated financial statements.

(2) Reserve values per McDaniel Report as at December 31, 2008.

(3) Internal estimate. See "Land" in this MD&A.

(4) Amounts are net of salvage value and in addition to amounts in the McDaniel Report for future well abandonment costs related to developed reserves. See "Asset retirement obligation" in this MD&A.

PET's three year history of net asset value and net asset value per Trust Unit, discounted at five percent and including distributions paid to Unitholders, is as follows.

Pre-tax net asset value at December 31, discounted at 5% ($ millions except per unit amounts)	**2008**	2007	2006
Net asset value	**1,200.9**	1,250.4	703.6
Net asset value per Trust Unit ($/Unit)	**10.63**	11.41	8.26
Distributions per Unit ($/Unit)	**1.20**	1.50	2.64
Net asset value per Trust Unit including distributions paid ($/Unit)	**11.83**	12.91	10.90

In the absence of adding reserves to the Trust, the NAV per Trust Unit will decline as the reserves are produced out. The cash flow generated by the production relates directly to the cash distributions paid to Unitholders. The above evaluation includes future capital expenditure expectations required to bring undeveloped reserves recognized by McDaniel that meet the criteria for booking under NI 51-101 on production. In order to independently assess the "going concern" value of the Trust, a more detailed independent assessment would be required of the upside potential of specific properties and the ability of the PET team to continue to make value-adding capital expenditures, some of which may require external financing.

At inception of the Trust in February 2003, based on the value of year-end 2002 reserves discounted at five percent and adjusted upward for the Trust's hedging and the Trust's forward gas price strip at the time, the NAV was determined to be $8.91 per Trust Unit. Since that time, including the December 2008 distribution paid on January 15, 2009, the Trust has distributed $13.124 per Trust Unit. Despite having distributed $4.214 per Trust Unit more in cash distributions than the initial NAV, the NAV as at December 31, 2008 increased to $10.63 per Trust Unit using a five percent discount rate.

MARKETING

Natural gas prices

Natural gas price ($/Mcfe, except percentages)	**2008**	2007	2006
Reference prices			
AECO Monthly Index	**8.13**	6.61	6.99
AECO Daily Index	**8.15**	6.49	6.53
Alberta Gas Reference Price (1)	**7.88**	6.21	6.74
Average PET prices			
Before financial hedging and physical forward sales (2)	**8.19**	6.44	6.61
Percent of AECO Monthly Index	**101**	97	95
Before financial hedging (3)	**8.15**	6.64	7.17
Percent of AECO Monthly Index	**100**	100	103
Including financial hedging and physical forward sales ("Realized" natural gas price)	**8.18**	7.44	7.52
Percent of AECO Monthly Index	**101**	113	108

(1) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties.

(2) PET's commodity hedging strategy employs both financial forward contracts and physical natural gas delivery contracts at fixed prices or price collars, as well as selling forward financial call options to counterparties. In calculating the Trust's natural gas price before financial and physical hedging, PET assumes all natural gas sales based on physical delivery fixed-price or price collar contracts during the period were instead sold at AECO monthly index.

(3) Natural gas price before financial hedging includes physical forward sales contracts for which delivery was made during the reporting period but excludes realized gains and losses on financial instruments.

U.S. natural gas prices are typically referenced to NYMEX at the Henry Hub, Louisiana while western Canada natural gas prices are referenced to the AECO Hub in Alberta. AECO Monthly Index prices increased 23 percent to average $8.13 per Mcf in 2008 as compared to $6.61 per Mcf for 2007, while AECO Daily Index prices increased 26 percent year over year. Natural gas prices experienced significant volatility in 2008. A decrease in North American gas storage levels earlier in the year coupled with a dramatic rise in the price of crude oil propelled the AECO Monthly Index price from $6.44 per Mcf for January 2008 to $11.39 per Mcf for July. This trend reversed course in the second half of the year as decreases in natural gas demand brought on by softening world economic conditions and relative increases in natural gas storage levels led to a decrease in the AECO Monthly Index from its mid-year highs to as low as $6.24 per Mcf in October 2008, rebounding to $7.21 per Mcf in December 2008 as a result of the onset of seasonal heating demand.

The Alberta Gas Reference Price is the monthly weighted average of intra-Alberta consumers' prices and ex-Alberta border prices, reduced by allowances for transporting and marketing gas, and is used to calculate Alberta Gas Crown Royalties. The Alberta Gas Reference Price increased 27 percent from $6.21 per Mcf in 2007 to $7.88 per Mcf in 2008, consistent with the increase in AECO monthly and daily index prices.

PET's average realized gas price was $8.18 per Mcfe in 2008, up ten percent from $7.44 per Mcfe in 2007. PET's natural gas price before financial hedging and physical forward sales increased 27 percent to $8.19 per Mcfe in 2008 from $6.44 per Mcfe in 2007, in line with the increase in AECO prices for the year.

Hedging and risk management

PET's gas price risk management strategy is focused on using financial instruments to mitigate the effect of commodity price volatility on funds flow and distributions, to lock in attractive economics on capital programs and acquisitions and to take advantage of perceived anomalies in natural gas markets. The Trust uses both financial hedge arrangements and physical forward sales to hedge up to a maximum of 60 percent of the trailing quarter's production including gas over bitumen deemed volumes in accordance with the limits under the Trust's credit facility and Hedging and Risk Management Policies. PET will also enter into foreign exchange swaps and physical or financial swaps related to the differential between natural gas prices at the AECO and NYMEX trading hubs in order to mitigate the effects of fluctuations in foreign exchange rates and basis differentials on the Trust's realized gas price. The term "financial instruments" includes all financial and physical risk management contracts. Although PET considers the majority of these risk management contracts to be effective economic hedges against potential gas price volatility, the Trust does not follow hedge accounting for its financial instruments.

PET's hedging activities are conducted by an internal Risk Management Committee under guidelines approved by the administrator's Board of Directors. PET's hedging strategy though designed to protect funds flow and distributions is opportunistic in nature. Depending on management's perceived position in the commodity price cycle the Trust may elect to reduce or increase its hedging position. The Trust mitigates credit risk by entering into risk management contracts with financially sound, credit-worthy counterparties.

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.

FINANCIAL RESULTS

Revenue

Revenue ($ thousands)	**2008**	2007	2006
Oil and natural gas revenue, before financial instruments (1)	**543,576**	412,571	401,635
Realized gains (losses) on financial instruments (2)	**(1,283)**	49,838	19,211
Call option premiums received (3)	**3,408**	-	-
Total oil and natural gas revenue	**545,701**	462,409	420,846

(1) Includes revenues related to physical forward sales contracts which settled during the period.

(2) Realized gains (losses) on financial instruments include settled financial forward contracts.

(3) Call option premiums received are included in unrealized gains (losses) on financial instruments in the statement of earnings, but are included in the calculation of the Trust's realized gas price and funds flows. Option premiums are reclassified to realized gains (losses) on financial instruments in the periods related to the option contracts.

Oil and natural gas revenue in 2008 was $545.7 million, representing an 18 percent increase from $462.4 million in 2007. The increase in revenue was a function of the ten percent increase in the Trust's average realized gas price in 2008 as compared to the prior year and a seven percent increase in production from 2007 to 2008.

Included in realized gains on financial instruments in 2008 is $13.0 million in financial instrument gains related to early termination of certain fixed-price forward natural gas contracts (2007 - $32.0 million).

The Trust recorded unrealized gains on financial instruments of $42.1 million in 2008, reflecting the change in the fair value of unsettled financial and physical forward natural gas and foreign exchange contracts during the year, as well as the $3.4 million in call option premiums received in 2008.

Funds flow

		2008		2007		2006
Funds flow reconciliation	**$ millions**	**($/Mcfe)**	$ millions	($/Mcfe)	$ millions	($/Mcfe)
Production volume (Bcfe)	**66.7**		62.1		56.0	
Revenue (1)	**545.7**	**8.18**	462.4	7.44	420.8	7.52
Royalties	**(92.3)**	**(1.38)**	(64.8)	(1.04)	(66.0)	(1.18)
Operating costs	**(120.6)**	**(1.81)**	(102.6)	(1.65)	(84.0)	(1.50)
Transportation costs	**(14.1)**	**(0.21)**	(12.7)	(0.20)	(11.9)	(0.21)
Operating netback from production	**318.7**	**4.78**	282.3	4.55	258.9	4.63
Gas over bitumen royalty adjustments	**20.8**	**0.31**	17.3	0.28	18.5	0.33
Lease rentals	**(3.5)**	**(0.05)**	(3.5)	(0.06)	(2.5)	(0.05)
General and administrative (2)	**(31.9)**	**(0.48)**	(24.7)	(0.40)	(16.6)	(0.30)
Interest and other (2)	**(13.7)**	**(0.20)**	(19.5)	(0.34)	(11.7)	(0.21)
Interest on convertible debentures (2)	**(15.0)**	**(0.23)**	(12.8)	(0.21)	(8.6)	(0.15)
Current taxes	**-**	**-**	-	-	(1.3)	(0.02)
Funds flow (2) (3)	**275.4**	**4.13**	239.1	3.82	236.7	4.23

(1) Revenue includes realized gains (losses) on financial instruments and call option premiums received.

(2) Excludes non-cash items.

(3) This is a non-GAAP measure, see "Significant Accounting Policies and Non-GAAP Measures" in this MD&A.

Royalties

PET pays Crown, freehold and gross overriding royalties that are dependent upon production volumes, commodity prices, location and age of producing wells and type of production. Gas Crown royalties are reduced by Gas Cost Allowance ("GCA") deductions. The GCA deductions are based on processing fees and allowable capital costs incurred at a property and are in accordance with Crown royalty regulations. Royalty income received is included in revenue. The effective royalty rate applicable to the Trust in 2008 was 16.9 percent (2007 – 14.0 percent) or $1.38 per Mcfe (2007 - $1.04 per Mcfe). The increase in royalty rate was primarily due to the 27 percent increase in the Alberta Gas Reference Price from year to year, as compared to a ten percent increase in the Trust's realized natural gas price.

Operating costs

Operating costs include all costs associated with the production of oil and natural gas from the wellhead to the point at which the product enters a sales pipeline for transport to market. Field gathering and processing costs are also included in operating costs. Revenue received from the processing of third party production at PET's facilities is netted against operating costs.

Operating costs totaled $120.6 million in 2008 as compared to $102.6 million in 2007. On a unit-of-production basis, operating costs increased by ten percent to $1.81 per Mcfe in 2008 from $1.65 per Mcfe in 2007. Operating costs increased as a result of higher production levels, higher property tax rates and $5.3 million in natural gas processing adjustments related to prior years that were recorded in 2008. Much of the total operating costs in the Northern district relate to the ongoing operation and maintenance of facilities and other infrastructure and are primarily fixed in nature.

Transportation costs

Costs to transport gas from the plant gate to the commercial market sales point are not reflected as an operating cost but rather are recorded as transportation costs for the product. Alberta's gas transportation system operates on a postage stamp basis. PET has reduced costs relative to the postage stamp costs through the execution of direct sales arrangements with end users of natural gas proximal to the Trust's producing fields in northeast Alberta. Total transportation costs increased by 11 percent to $14.1 million in 2008 from $12.7 million in 2007, in line with the increase in production levels from year to year. On a unit-of-production basis, transportation costs increased five percent from $0.20 per Mcfe in 2007 to $0.21 per Mcfe in 2008, as a higher percentage of the Trust's production came from the Southern district assets which are not subject to direct sales arrangements.

Operating netbacks

A seven percent increase in production levels and a ten percent increase in the Trust's realized natural gas price were the primary drivers in increasing PET's operating netback by $36.4 million to $318.7 million ($4.78 per Mcfe) for the year ended December 31, 2008 from $282.3 million ($4.55 per Mcfe) for the prior year.

Operating netback reconciliation ($ millions)	($ millions)
Realized price increase	49.3
Production increase	34.0
Royalty increase	(27.5)
Operating cost increase	(18.0)
Transportation increase	(1.4)
Increase in operating netback	36.4

Gas over bitumen royalty adjustments

In 2004 and 2005 the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas ("Royalty Regulation"), which 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 certain bitumen conservation decisions. The 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 a 50 percent reduction factor. The components of netbacks for the gas over bitumen shut-in reserves are outlined below.

Gas over bitumen royalty adjustment netback ($ per Mcf)	**2008**	2007	2006
Average deemed volume (MMcf/d)	**19.2**	19.9	20.8
Gas price	**7.88**	6.21	6.74
Royalties	**(1.58)**	(1.24)	(1.35)
Operating costs	**(0.40)**	(0.40)	(0.40)
50% reduction factor	**(2.95)**	(2.28)	(2.49)
Gas over bitumen royalty adjustment netback	**2.95**	2.29	2.50

The Trust's 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. Deemed production decreased by 0.7 MMcf/d from the 19.9 MMcf/d recorded for 2007 as a result of the annual ten percent reduction in deemed production volumes discussed previously and the sale of 0.6 MMcf/d of deemed production in October 2008, partially offset by the full year effect of the acquisition of approximately 2.0 MMcf/d of deemed production in the second quarter of 2007. Current deemed production is approximately 18.7 MMcf/d.

The majority of royalty adjustments received have been recorded on PET's balance sheet rather than reported as income as the Trust cannot determine if, when or to what extent the royalty adjustments may be repayable through incremental royalties if and when gas production recommences. Royalty adjustments may be repayable to the Crown in the form of an overriding royalty on gas production from wells which resume production within the gas over bitumen area. However, all royalty adjustments are recorded as a component of funds flow.

In 2008 PET disposed of certain shut-in gas wells in the gas over bitumen area for proceeds of $5.6 million, recording a $4.5 gain on sale of property, plant and equipment. As part of the disposition agreement the ownership of the natural gas reserves is transferred to the buyer and as such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer PET's responsibility, nor does the Trust retain the right to future gas over bitumen royalty adjustments. As a result of this disposition, the gas over bitumen royalty adjustments received to the date of the disposition by the Trust, for the affected wells, are now considered revenue since they will not be repaid to the Crown. As a result the Trust reclassified $2.1 million in previous gas over bitumen royalty adjustments from the balance sheet to the statement of earnings.

In 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. As a result of this disposition, the gas over bitumen royalty adjustments received by the Trust for the affected wells are now considered revenue since they will not be repaid to the Crown.

In 2008, the Trust received $20.8 million in gas over bitumen royalty adjustments. Cumulative royalty adjustments received to December 31, 2008 total $98.3 million.

Lease rentals

Lease rentals reflect annual payments made to the Alberta Crown or other land owners in order to maintain the rights to explore previously-acquired undeveloped acreage. These payments are expensed by the Trust in accordance with the successful efforts method of accounting for oil and gas assets, whereas they are typically capitalized by companies employing the full cost method of accounting. Lease rentals totaled $3.5 million in 2008, as higher lease rental payments resulting from a full year of activity from the Birchwavy Assets were offset by lease rental recoveries of $0.3 million received during the year for the lease of a portion of PET's fee-simple lands.

General and administrative expenses

		2008		2007		2006
General and administrative expenses	**$000's**	**$/Mcfe**	$000's	$/Mcfe	$000's	$/Mcfe
Cash general & administrative	**31,955**	**0.48**	24,670	0.40	16,635	0.30
Trust Unit-based compensation (1)	**5,671**	**0.09**	4,287	0.07	3,337	0.06
Total general & administrative	**37,626**	**0.57**	28,957	0.47	19,972	0.36

(1) Non-cash item

General and administrative expenses ("G&A") include costs incurred by PET which are not directly associated with the production of oil and natural gas. The most significant components of G&A expenses are office staff compensation costs and information technology costs. Field employee compensation costs are charged to operating expenses. Overhead recoveries resulting from the allocation of administrative costs to producing properties and capital projects are recorded as a reduction of G&A expenses.

G&A expenses, net of overhead recoveries on operated properties, increased to $37.6 million from $29.0 million in 2007 and increased on a unit-of-production basis from $0.47 per Mcfe in 2007 to $0.57 per Mcfe in 2008. The increase in 2008 is largely the result of the full year effect of additional staffing requirements related to the Birchwavy Acquisition, as well as the ongoing focus on new venture opportunities in the Trust's portfolio. PET moved its head office to leased space in December 2007 following the sale of its previous premises and as a result the Trust now incurs office lease expense, which totaled $2.8 million for 2008. Trust Unit-based compensation increased by $1.4 million in 2008 due to a higher number of incentive rights outstanding and higher volatility estimates used in the unit-based compensation expense calculation as compared to the prior year. Compensation expense is calculated on unit incentive rights at the time of issue using a binomial option pricing model, and is not adjusted for subsequent changes in the value of the incentive rights as a result of changing market conditions.

Interest expense

Interest and other expense decreased to $13.8 million in 2008 from $21.4 million in 2007 as a result of a decrease in short-term interest rates on the Trust's credit facility to an average of 4.3 percent in 2008 from 5.5 percent in the prior year. Interest and other expense in 2008 also includes a loss on investment of $0.2 million related to the decline in market value of the Trust's investment in Ember Resources Inc. ("Ember"), a publicly traded oil and gas exploration company to December 31, 2008 (loss on investment in 2007 - $1.9 million). The Trust previously had an investment in Cordero Energy Inc. ("Cordero"). On July 4, 2008, Cordero entered into an agreement to sell all of its outstanding common shares to Ember in exchange for a combination of cash and common shares of the acquirer. The transaction between Cordero and Ember closed on September 5, 2008, at which time the Trust recorded proceeds on disposition of marketable securities of $0.8 million related to the cash component of the transaction.

In 2008, $18.3 million of interest on convertible debentures was expensed as compared to $15.6 million in 2007. The increase was due to a full year of interest expense on the 6.5 percent convertible debentures (the "2007 6.5% Debentures") issued June 2007 as partial funding for the Birchwavy Acquisition. Included in interest on convertible debentures for 2008 is $3.3 million of non-cash expenses related primarily to the amortization of debt issue costs (2007 - $2.8 million).

Funds flow

Higher operating netbacks and a decrease in interest expense resulted in funds flow netbacks increasing eight percent from $3.82 per Mcfe in 2007 to $4.13 per Mcfe in 2008. Funds flow increased by 15 percent to $275.4 million ($2.47 per Trust Unit) for the year ended December 31, 2008 from $239.1 million ($2.44 per Trust Unit) in the 2007 period, as a result of the increase in revenues, partially offset by higher royalties and operating costs. The effect on funds flow per Trust Unit was dampened by the increased number of Trust Units outstanding as a result of financing activities for the Birchwavy Acquisition and the issuance of Trust Units through PET's Distribution Reinvestment and Optional Unit Purchase Plan ("DRIP").

Exploration expense

Exploration costs include lease rentals paid on undeveloped lands, seismic expenditures and expired leases and are expensed by the Trust in accordance with the successful efforts method of accounting for oil and gas assets, whereas they are typically capitalized by companies employing the full cost method of accounting. Exploration expenses totaled $34.1 million in 2008 as compared to $18.8 million in 2007, as a result of an increase in lease expiries to $9.5 million in 2008 from $4.2 million in 2007 and an impairment charge of $12.0 million related to a decrease in fair market value of the Trust's undeveloped land in certain core areas in the Northern district. For the purpose of the impairment test on undeveloped properties, fair values are derived from recent average land sale prices in each core area and are not necessarily indicative of the potential opportunities on the Trust's land base, many of which have already been identified in PET's prospect inventory.

Depletion, depreciation and accretion

PET's 2008 depletion, depreciation and accretion ("DD&A") rate decreased to $3.28 per Mcfe from $3.54 per Mcfe in 2007 primarily due to the lower cost per Mcfe of proved reserves associated with the Birchwavy Acquisition, as well as improved finding and development costs for proved reserves in 2008 as compared to prior years. DD&A expense was also reduced by a $4.4 million recovery resulting from a revision in the asset retirement obligation for the Trust's Saskatchewan cost centre, partially offset by an impairment charge of $2.7 million related to a non-core property group outside of the Trust's two primary operating districts. PET calculates its depletion factor using proved reserves for acquired properties, proved developed reserves for other properties and production volumes. Gas over bitumen deemed production is not included in the DD&A calculation. The DD&A rate includes accretion expense on the asset retirement obligation of $13.9 million in 2008 as compared to $10.7 million in 2007. The increase in accretion is a function of the Trust's expanding asset base resulting primarily from the Birchwavy Acquisition completed in June 2007.

Depletion, depreciation and accretion ($ thousands except per Mcfe amounts)	**2008**	2007	2006
Depletion expense	**204,638**	209,496	192,052
Accretion of asset retirement obligation	**13,904**	10,672	7,187
Total	**218,542**	220,168	199,239
Per unit-of-production ($/Mcfe)	**3.28**	3.54	3.56

At year-end 2008, property, plant and equipment costs include $126.8 million (2007 - $142.9 million) currently not subject to depletion and $26.8 million (2007 - $27.5 million) of costs related to shut-in gas over bitumen reserves which are not being depleted due to the non-producing status of the wells in the affected properties.

Asset retirement obligation

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, facilities and pipelines, including estimated costs to abandon the wells, facilities and pipelines and reclaim the sites and the estimated 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 "Total proved and probable reserves" in the "NPV of reserves" table in this MD&A. Of the total future well abandonment costs included in the McDaniel Report an undiscounted 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.

				Discounted at
Abandonment and reclamation costs ($ millions)	0%	5%	8%	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	(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.

The asset retirement obligation presented in PET's financial statements is discounted using an estimate of the timing of asset retirement expenditures and PET's estimated credit-adjusted discount rate, which is reviewed and adjusted annually for changes in credit markets and other internal and external factors. These expenditures are currently expected to occur over the next 25 years with the majority of costs incurred between 2015 and 2020. PET's discounted asset retirement obligation decreased from $194.1 million at December 31, 2007 to $179.7 million at December 31, 2008 primarily due to a reduction in the estimate of abandonment and reclamation expenditures for wells and an increase in the Trust's credit-adjusted interest rate.

Income taxes

On June 22, 2007, new legislation was passed (the "Trust Tax Legislation") pursuant to which certain distributions will be subject to a trust-level tax and will be characterized as dividends to the Unitholders, commencing January 1, 2011.

Once the Trust Tax Legislation becomes applicable to PET, distributions to PET's Unitholders will no longer be deductible in computing the Trust's 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.

The new trust tax applies to PET effective January 1, 2011 assuming the Trust continues to comply with the normal growth provisions as outlined by the federal government. Specifically, normal growth includes equity growth within certain safe harbour limits measured by reference to a Specified Investment Flow Through's ("SIFT") market capitalization as of the end of trading on October 31, 2006. The safe harbour calculation is calculated as a percentage of the market value of the SIFT's issued and outstanding publicly-traded trust units and not including any convertible debt, options or other interests convertible into or exchangeable for trust units. The safe harbour limit is 100 percent of PET's market capitalization at October 31, 2006.

These limits are cumulative, so that any unused limit for a period carries over into the subsequent period. Additional details of the guidelines include the following:

(i) new equity for these purposes includes units and debt that is convertible into units, and may include other substitutes for equity;

(ii) replacing debt that was outstanding as of October 31, 2006 with new equity, whether by a conversion into trust units of convertible debentures or otherwise, will not be considered growth for these purposes and will therefore not affect the safe harbour; and

(iii) the exchange, for trust units, of exchangeable partnership units or exchangeable shares that were outstanding on October 31, 2006 will not be considered growth for these purposes and will therefore not affect the safe harbour where the issuance of the trust units is made in satisfaction of the exercise of the exchange right by a person other than the SIFT.

PET's market capitalization as of the close of trading on October 31, 2006, having regard only to its issued and outstanding publicly-traded Trust Units, was approximately $1.4 billion, which means the Trust's safe harbour equity growth amount through the period ending December 31, 2010 was approximately $1.4 billion, not including equity issued to replace the Trust's debt that was outstanding on October 31, 2006, including convertible debentures. Failure to comply with the "normal growth" provisions as outlined would result in the Trust being subject to the new tax immediately, as opposed to January 1, 2011. Since October 31, 2006 PET has issued approximately $388 million of new Trust Units and convertible debentures through a public offering of Trust Units and convertible debentures in 2007, the Trust's DRIP plan and Unit Incentive Plan.

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:

- 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
- 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.

The draft legislation released by the Department of Finance also provided guidelines to enable the conversion of existing income trusts and other SIFT entities into public corporations without immediate tax consequences to the SIFTs or their investors. The amendments will allow such conversions from that date until 2013. The proposals generally facilitate the conversion of SIFTs into corporations and reflect the government's intention to permit SIFTs to convert to corporate status on a tax-deferred basis while mitigating undue tax effects.

Among other things, the proposed amendments provide for:

- the tax-deferred exchange of SIFT trust units by a Unitholder to a taxable Canadian corporation for shares of the corporation without any administrative requirement to file election forms (Unit-for-Share Exchange);
- the tax-deferred distribution of properties of a SIFT trust to a taxable Canadian corporation (Wind-up Distribution);
- the flow-through of unused tax attributes of a SIFT trust to a taxable Canadian corporation as a consequence of a Wind-up Distribution; and
- the tax-deferred distribution of shares of a taxable Canadian corporation from a SIFT trust to the public (Share Distribution).

A variety of tax and other factors need to be weighed in determining if and when PET should adjust its business and legal structure. Now that detailed rules are available on the mechanics for conversion, the Trust is in a better position to evaluate its options and determine the optimal course of action for PET's assets and business strategy going forward. PET is currently analyzing potential structures and courses of action however the Trust has not yet made a determination with respect to future changes in the structure of its business operations, if any.

PET recorded future tax expense and a future tax liability of $16.1 million for 2008 (2007 – nil). Based on production forecasts for PET's reserves included in the independent reserve report as at December 31, 2008, and funds flows based on current forward AECO prices for natural gas, the book values of the Trust's assets are projected to exceed the related tax values on January 1, 2011, the date the direct tax on distributions within the Trust becomes effective. Future income tax is a non-cash expense and does not affect the Trust's funds flows or its cash available for distributions.

At December 31, 2008, the Trust's consolidated income tax pools are estimated as follows. Actual tax pool amounts will vary as tax returns are finalized and filed. PET intends to maximize the preservation of tax pools over the transition period in order to minimize the tax consequences faced by the Trust in 2011 and future years.

Tax pool information ($ millions)	As at December 31, 2008
Canadian oil and gas property expense (COGPE)	299.9
Canadian development expense (CDE)	91.0
Canadian exploration expense (CEE)	6.1
Undepreciated capital cost (UCC)	190.7
Trust unit issue costs	14.6
Non-capital losses	93.3
Total	695.6

Net earnings

Net earnings totaled $30.8 million or $0.28 per basic Trust Unit ($0.27 per diluted Trust Unit) in 2008 as compared to a net loss of $32.9 million or $0.33 per basic and diluted Trust Unit in 2007, as a result of higher funds flows and an unrealized gain on financial instruments of $42.1 million, partially offset by future tax expense of $16.1 million. The loss in 2007 was primarily due to an unrealized loss on financial instruments of $35.4 million.

FOURTH QUARTER INFORMATION SUMMARY

Fourth quarter information ($ thousands except per Trust Unit, per Mcfe and percent amounts)	Three months ended December 31 **2008**	2007	% change
Daily production volumes (MMcfe/d)	**173.1**	190.3	(9)
Oil and natural gas revenues	**109,090**	109,919	(1)
Realized gains (losses) on financial instruments	**8,665**	13,828	(37)
Call option premiums received	**3,408**	-	100
Oil and natural gas revenues, after financial instruments	**121,163**	123,747	(2)
Natural gas price, before financial hedging and physical forward sales ($/Mcfe)	**$ 6.84**	$ 6.19	11
Realized natural gas price ($/Mcfe)	**$ 7.61**	$ 7.07	8
Royalties	**18,083**	15,202	19
Royalties as a percentage of revenues (%)	**14.9**	12.3	21
Operating expenses	**26,265**	29,221	(10)
Per Mcfe	**$ 1.65**	$ 1.67	(1)
General and administrative (“G&A”) expenses	**10,697**	7,733	38
Per Mcfe	**$ 0.67**	$ 0.44	52
Funds flow	**61,513**	59,622	3
Per Trust Unit	**$ 0.55**	$ 0.55	-
Cash flow provided by operating activities	**69,179**	38,224	81
Per Trust Unit	**$ 0.61**	$ 0.35	74
Net loss	**(8,986)**	(4,970)	81
Per Trust Unit	**$ (0.08)**	$ (0.05)	60
Capital expenditures – exploration and development	**28,329**	20,270	40

In comparing the fourth quarter of 2008 with the same period in 2007:

- Production decreased nine percent to 173.1 MMcfe/d, as lower production due to asset dispositions, cold-weather related downtime and natural production declines in the Northern district and delays in bringing on new production in the Southern district due to third party-operated facility constraints was partially offset by new production additions from the Trust’s 2008 capital programs.
- Realized natural gas prices were eight percent higher in the fourth quarter of 2008 as a result of higher AECO daily spot and monthly index prices compared to the three months ended December 31, 2007.
- The Trust’s royalty rate of 14.9 percent of revenues was 35 percent greater than 2007 and lower than the Trust’s historical royalty rates as realized natural gas prices were well above the Alberta Gas Reference Price in both quarters.
- General and administrative expenses increased $3.0 million from the fourth quarter of 2007, as a result of higher unit-based compensation expenses.
- Operating costs decreased $3.0 million due to lower production volumes. On a unit-of-production basis operating costs were consistent from quarter to quarter.
- Funds flow increased $1.9 million to $61.5 million for the fourth quarter of 2008 as higher royalty expenses were more than offset by lower operating costs and interest expense. PET’s long term bank debt balance decreased from $342.2 million at December 31, 2007 to $277.0 million at December 31, 2008.
- Net loss totaled $9.0 million for the three months ended December 31, 2008, resulting from future tax expense of $16.1 million and an impairment charge on undeveloped lands of $12.0 million, partially offset by an unrealized gain on financial instruments of $22.8 million. The $5.0 million loss in the fourth quarter of 2007 is the result of a $17.4 million unrealized loss on financial instruments in the period.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Capitalization and financial resources ($ thousands except per Trust Unit and percent amounts)	**2008**	Year ended December 31 2007	2006
Long term bank debt	**276,976**	342,190	222,923
Convertible debentures, measured at principal amount	**236,034**	236,109	161,134
Working capital deficiency (surplus) (2)	**7,859**	(6,519)	22,561
Net debt	**520,869**	571,780	406,618
Trust Units outstanding at end of period (thousands)	**112,968**	109,557	85,186
Market price at end of period	**5.05**	6.30	12.40
Market value of Trust Units	**570,488**	690,209	1,056,306
Total capitalization (1)	**1,091,357**	1,261,909	1,462,924
Net debt as a percentage of total capitalization (%)	**47.7**	45.3	27.8
Annualized fourth quarter funds flow (1)	**246,052**	238,488	232,664
Net debt to funds flow ratio (times) (1)	**2.1**	2.4	1.7

(1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in this MD&A.

(2) Working capital deficiency (surplus) excludes short-term financial instrument assets and liabilities related to the Trust's hedging activities and the current portion of convertible debentures.

PET has a demand credit facility with a syndicate of Canadian chartered banks. The revolving feature of the facility expires on May 25, 2009 if not extended. Upon expiry of the revolving feature of the facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity of one additional year. The borrowing base on the facility is currently $400 million, comprised of a $390 million production component and a $10 million working capital component. The Trust's lenders have completed their semi-annual borrowing base redetermination, resulting in a reconfirmation of the Trust's borrowing base at $400 million through April 30, 2009. Collateral for the credit facility is provided by a floating-charge debenture covering all existing and acquired property of the Trust as well as unconditional full liability guarantees from all subsidiaries (excluding Severo) in respect of amounts borrowed under the facility. Bank debt decreased to $277.0 million at December 31, 2008, as compared to $342.2 million at December 31, 2007 as a result of property dispositions during the year and funds flow in excess of distributions and exploration and development expenditures, as well as proceeds received through the Trust's DRIP program. In addition to amounts outstanding under the credit facility PET has outstanding letters of credit in the amount of $4.4 million.

In 2008 Severo established a separate credit facility with a Canadian chartered bank in the amount of $10 million. The facility is due on demand, and the borrowing base is reviewed annually in October. Collateral for the facility is provided by a floating charge covering all property of Severo. As of December 31, 2008, Severo had drawn $9.8 million on the facility. Due to the demand nature of the facility, all related borrowings are classified as current liabilities on the Trust's balance sheet.

PET has a working capital deficiency of $7.9 million at December 31, 2008, as compared to a surplus of $6.5 million at December 31, 2007. The decrease in working capital is primarily related to the classification of the Severo credit facility as a current liability, and higher accrued liabilities due to increased capital spending in the fourth quarter of 2008 as compared to the fourth quarter of 2007. The Trust's working capital deficiency will be funded from future sales revenues and by additional borrowings from PET's credit facility, as required.

Net debt as a percentage of total capitalization increased to 47.7 percent at year-end 2008 as compared to 45.3 percent in the prior year, as a result of a decline in the market price of the Trust's Units during the year. Net debt to annualized fourth quarter funds flow fell to 2.1 times for the three months ended December 31, 2008 from 2.4 times for the three months ended December 31, 2007 due to lower net debt levels. A reconciliation of the change in net debt from December 31, 2007 to December 31, 2008 is as follows.

Reconciliation of net debt ($ millions)	
Net debt, December 31, 2007	571.8
Capital expenditures (exploration & development and other)	127.7
Dispositions, net of acquisitions	(18.5)
Funds flow	(275.4)
Distributions	133.9
Proceeds from DRIP plan	(23.5)
Proceeds from exercise of unit incentive rights	(0.3)
Expenditures on asset retirement obligations	5.2
Net debt, December 31, 2008	**520.9**

The Trust expects that its distributions and capital expenditure program for 2009 will be funded by funds flow. However, changes in natural gas prices, cash netbacks and production levels can affect future capital spending plans and distributions.

PET's future contractual obligations are summarized in the following table:

Contractual obligations ($ millions)	Total	Less than 1 year	2-3 years	4-5 years	After 5 years
					Payments due by period
Bank and other debt [1]	286.8	9.8	277.0	-	-
Convertible debentures	236.0	5.8	230.2	-	-
Pipeline commitments [2]	16.1	7.1	5.5	1.2	2.3
Total contractual obligations	538.9	22.7	512.7	1.2	2.3

(1) The revolving feature of the credit facility expires on May 25, 2009 if not extended. Upon expiry of the revolving feature of the facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity date of one additional year.

(2) The Trust has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada.

Interest payments on financial liabilities ($ millions)	Total	2009	2010-2013	Thereafter
Interest payment on bank debt [1]	10.5	7.5	3.0	–
Interest on convertible debentures [2]	37.1	14.9	22.2	–
Total interest obligations	47.6	22.4	25.2	–

(1) Assuming revolving feature of the credit facility is not extended and calculated at the December 31, 2008 effective interest rate of 2.62%, assuming a constant debt level equivalent to the balance at December 31, 2008.

(2) Assuming payment of interest is not settled in Trust Units, at the option of PET.

Convertible debentures

As at December 31, 2008, the Trust had 6.5 percent convertible debentures issued in June 2007 (6.5% Debentures), 6.25 percent convertible debentures issued in April 2006 (2006 6.25% Debentures), 6.25 percent convertible debentures issued in April 2005 (2005 6.25% Debentures) and 8 percent convertible debentures issued in July 2004 (8% Debentures) outstanding as follows:

Convertible debentures series ($ millions, except as noted)	6.50%	2006 – 6.25%	2005 – 6.25%	8%
Principal issued	75.0	100.0	100.0	48.0
Principal outstanding	74.9	100.0	55.3	5.9
Maturity date	June 30, 2012	April 30, 2011	June 30, 2010	September 30, 2009
Conversion price ($ per Trust Unit)	14.20	23.80	19.35	14.20
Fair market value	44.4	70.0	52.0	5.7

All series of debentures are redeemable by the Trust at a premium to face value, pay interest semi-annually and are subordinated to substantially all other liabilities of PET including the credit facility. Fair values of debentures are calculated by multiplying the number of debentures outstanding at December 31, 2008 by the quoted market price per debenture at that date. During 2008 $0.1 million of the 6.5% Debentures were converted into Trust Units.

Unitholders' equity

PET's total capitalization was $1.1 billion at December 31, 2008 with the market value of the Trust Units representing 52.3 percent of total capitalization. During 2008, the market price of the Trust Units ranged from $4.40 to $10.25 with an average daily trading volume of 521,357 Trust Units.

PET has a distribution reinvestment and optional Unit purchase plan ("DRIP plan") which provides Unitholders with 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 price of the Trust Units for the ten trading days immediately proceeding a distribution payment date ("Treasury Purchase Price"). As well, subject to thresholds and restrictions described in the DRIP plan, it contains a provision for the purchase by Canadian unitholders of additional Trust Units with optional cash payments of up to $100,000 per participant per fiscal year of PET at the same six percent discount to the Treasury Purchase Price. No additional commissions, service or brokerage fees are charged to the Unitholder for these transactions. In 2008 the DRIP plan resulted in an additional 3,265,000 Trust Units (2007 – 3,675,000 Trust Units) being issued at an average price of $7.22 (2007 - $8.95) raising a total of $23.5 million (2007 - $32.9 million).

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.

Weighted average Trust Units outstanding for 2008 totaled 111.5 million (2007 – 98.1 million). On December 31, 2008 there were 113.0 million Trust Units outstanding. In addition to issuances under the DRIP plan, 140,000 Trust Units were issued during 2008 by way of exercised Incentive Rights and Bonus Rights for net proceeds of $0.3 million.

DISTRIBUTIONS

Distributions are determined monthly by the Board of Directors of the Trust's administrator taking into account PET's forecasted production, capital spending and cash flow, forward natural gas price curves, the Trust's current hedging position, targeted debt levels and debt repayment obligations. The following items are considered in arriving at cash distributions to Unitholders:

- Base production forecasts;
- Current financial and physical forward natural gas sales contracts;
- Forward market for natural gas prices;
- Exploration and development expenditures;
- Projected production additions;
- Debt repayments to the extent required or deemed appropriate by management to preserve balance sheet strength for future opportunities;
- Working capital requirements; and
- Site reclamation and abandonment expenditures.

PET declared cash distributions of $133.9 million ($1.20 per Unit) in 2008 representing 48.6 percent of annual funds flow, bringing total cumulative distributions since inception to year-end 2008 to $951.1 million ($13.124 per Trust Unit). In 2007, declared cash distributions were $145.8 million ($1.50 per Trust Unit), representing 61.0 percent of funds flow. PET's business strategy targets sustainability with a capital program sufficient to maintain production levels and with the remaining cash flow available for distribution to Unitholders. The Trust's monthly distribution was adjusted to $0.07 per Trust Unit per month in January 2009 to preserve sustainability and strengthen its balance sheet in light of weaker natural gas prices and an uncertain economic climate. The payout ratio in future periods will largely be determined by the Trust's capital spending plans and resulting production levels, royalty rates, operating costs and natural gas prices, which have experienced significant volatility in 2008.

PET anticipates that distributions and development capital expenditures for 2009 will be funded by funds flow; however, changes in natural gas prices, cash netbacks and production levels can affect future capital spending plans and distributions. Acquisitions will continue to be funded through a combination of internally generated funds, equity offerings and debt financing.

	Year ended December 31	
Distributions ($ thousands)	**2008**	2007
Cash flows provided by operating activities	**259,764**	222,937
Net earnings (loss)	**30,785**	(32,859)
Distributions	**133,921**	145,829
Excess of cash flows provided by operating activities over distributions	**125,843**	77,108
Shortfall of net earnings (loss) over distributions	**(103,136)**	(178,688)

The Trust targets long-term sustainability of both its production base and distributions to Unitholders. As such, PET's distribution rates are designed to result in an excess of cash flows provided by operating activities over distributions which will provide the majority of the funding for PET's exploration and development expenditures for the respective periods. The excess of $125.8 million (2007 - $77.1 million) compares to exploration and development expenditures of $126.1 million for the year ended December 31, 2008 (2007 - $118.0 million). The excess of cash flows provided by operating activities over distributions increased significantly in 2008 as compared to 2007 as the Trust recorded higher cash flows from operating activities, and adjusted its distribution rate in mid-2007 and again in January of 2009 in order to preserve sustainability. In periods where the excess of cash flows provided by operating activities over distributions is less than exploration and development expenditures, the shortfall is funded by additional bank borrowings and external financing activities as appropriate.

The Trust has an excess of distributions over net earnings (loss) in 2008 and 2007, and distributions are likely to continue to exceed net earnings in future periods. PET does not typically compare distributions to earnings due to the significant impact of non-cash items on earnings such as unrealized gains and losses on financial instruments, asset impairment charges and DD&A, which have no impact on the Trust's ability to pay distributions. Where distributions exceed net earnings, a portion of the cash distributions declared may represent an economic return of capital to the Trust's Unitholders.

Taxation of 2008 cash distributions

Cash distributions are comprised of a return of capital portion (tax deferred) and a return on capital portion (taxable). In order to preserve tax pools to shield the Trust from SIFT income taxes in 2011 and beyond, PET has elected to minimize its tax pool claims in 2008. As such, cash distributions received or receivable by a Canadian resident, outside of a registered pension or retirement plan in the 2008 taxation year, are 100 percent taxable. Consistent with the Trust's strategy of conserving tax pools, distributions are expected to be 100 percent taxable for the foreseeable future.

2008 Distributions by month ($ per Trust Unit) Payment Date	Canadian Taxable Amount	Canadian Tax Deferred Amount (Return of capital)	Total Distribution
February 15, 2008	0.10	0.00	0.10
March 17, 2008	0.10	0.00	0.10
April 15, 2008	0.10	0.00	0.10
May 15, 2008	0.10	0.00	0.10
June 16, 2008	0.10	0.00	0.10
July 15, 2008	0.10	0.00	0.10
August 15, 2008	0.10	0.00	0.10
September 15, 2008	0.10	0.00	0.10
October 15, 2008	0.10	0.00	0.10
November 17, 2008	0.10	0.00	0.10
December 15, 2008	0.10	0.00	0.10
January 15, 2009	0.10	0.00	0.10
Total (1)	1.20	0.00	1.20
Percent of distribution	100	0	100

(1) Total is based upon cash distributions declared during 2008.

SUMMARY OF QUARTERLY RESULTS

Quarterly information - 2008 ($ thousands except where noted)	**Dec 31, 2008**	Sept 30, 2008	June 30, 2008	Three months ended Mar 31, 2008
Oil and natural gas revenues before royalties (1)	**109,090**	149,216	166,199	121,878
Natural gas production (MMcfe/d)	**173.1**	183.7	188.4	183.8
Funds flow (2)	**61,513**	76,380	81,350	56,191
Per Trust Unit - basic	**0.55**	0.68	0.73	0.51
Net earnings (loss)	**(8,986)**	180,796	(55,365)	(85,660)
Per Trust Unit - basic	**(0.08)**	1.62	(0.50)	(0.78)
- diluted	**(0.08)**	1.60	(0.50)	(0.78)
Realized natural gas price ($/Mcfe)	**7.61**	8.78	9.00	7.29
Average AECO Monthly Index price ($/Mcf)	**6.79**	9.25	9.35	7.13

Quarterly information - 2007 ($ thousands except where noted)	Dec 31, 2007	Sept 30, 2007	June 30, 2007 (3)	Three months ended Mar 31, 2007
Oil and natural gas revenues before royalties (1)	109,919	98,508	104,451	99,693
Natural gas production (MMcfe/d)	190.3	193.1	155.0	141.7
Funds flow (2)	59,622	41,212	72,669	65,597
Per Trust Unit - basic	0.55	0.38	0.81	0.76
Net earnings (loss)	(4,970)	5,246	9,218	(39,261)
Per Trust Unit - basic	(0.05)	0.05	0.10	(0.46)
- diluted	(0.05)	0.05	0.10	(0.46)
Realized natural gas price ($/Mcfe)	7.07	5.66	8.80	8.94
Average AECO Monthly Index price ($/Mcf)	6.00	5.61	7.37	7.46

(1) Excludes realized and unrealized gains (losses) on financial instruments.

(2) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in this MD&A.

(3) The Trust's net earnings for the three and six months ended June 30, 2007 have been restated to reflect the correction of an error with respect to the vesting period over which certain unit-based compensation liabilities were expensed. The correction results in an increase to net earnings for the three and six months ended June 30, 2007 of $3.1 million.

Oil and natural gas revenues are a function of production levels and natural gas prices. Production levels increased significantly with the Birchwavy Acquisition in June 2007, and revenues have increased in the last six quarters as a result. Revenues were highest in the second and third quarters of 2008 when AECO prices are highest, averaging $9.30 per Mcf, and lowest in the third quarter of 2007 when the AECO monthly index price was $5.61 per Mcf. The Trust uses financial instruments to mitigate the effect of volatility in AECO prices on funds flows, and therefore funds flows will trend with PET's realized gas price and changes in production levels. Funds flows were highest in the second and third quarters of 2008 and lowest in the third quarter of 2007 when the realized gas price was $5.66/Mcfe.

Net earnings were highest in the third quarter of 2008 as a result of unrealized gains on financial instruments of $168.9 million for the period. The net losses in the first quarter of 2007 and the first and second quarters of 2008 were due to unrealized losses of $48.5 million, $79.2 million and $70.4 million respectively on the change in mark-to-market value of PET's financial instruments during those periods. The net loss in the fourth quarter of 2008 is due to future tax expense of $16.1 million and an impairment charge on undeveloped lands of $12.0 million.

2009 OUTLOOK AND SENSITIVITIES

With the continuing decline in natural gas prices, the Board of Directors of the Trust has revised downward its operating and capital budget for 2009. PET is now budgeting for a base capital expenditure program of $65 million for 2009, down from its previous budget of $87 million and its original budget of $113 million. Approximately $40 million will have been expended by the end of the first quarter with positive results thus far, generating more than 16 MMcf/d of production which is expected to come onstream by early April.

With the current outlook for natural gas prices for the remainder of 2009, the Trust expects to spend the additional $25 million after break-up and continue through the second half of the year, high-grading drilling activity to those opportunities that are land-preserving or strategic in nature. PET has pre-planning work in place to scale back up to a larger program should natural gas prices and other factors support an expanded capital program.

Incorporating the anticipated results from the revised capital budget program, PET expects natural gas production of 170 to 175 MMcfe/d. Based on the current forecast for natural gas prices incorporating the Trust's forward sales contracts, PET forecasts that the 2009 capital program and distributions will be funded entirely through 2009 funds flow.

The following table shows PET's estimate of key measures for 2009 based on its hedging portfolio, production levels and the Trust's estimated exploration and development capital expenditures and targeted results for full year 2009 under several different full year 2009 AECO gas price assumptions.

	Average full year AECO monthly index gas price ($/GJ) (4)			
Funds flow outlook	$4.00	$5.00	$6.00	$7.00
Oil and natural gas production (MMcfe/d)	175	175	175	175
Realized gas price ($/Mcfe)	6.21	6.69	7.17	7.65
Funds flow, excluding 2009 hedging (1) (2) ($millions)	63	118	168	211
Per Trust Unit (1) (2) ($/Unit/month)	0.046	0.087	0.124	0.155
Funds flow, including 2009 hedging (1) ($millions)	187	206	220	227
Per Trust Unit (1) ($/Unit/month)	0.138	0.152	0.162	0.167
Payout ratio (1) (5) (%)	39	35	33	32
Ending net debt to cash flow ratio (3) (times)	2.6	2.2	2.0	2.0

(1) These are non-GAAP terms; please refer to "Significant accounting policies and non-GAAP measures" in this MD&A.

(2) Amount excludes projected funds flows from the Trust's 2009 financial and physical forward sales portfolio.

(3) Calculated as ending net debt (including convertible debentures) divided by annualized funds flow.

(4) Average AECO settled and forward price for 2009 as at March 9, 2009 was $4.73 per GJ.

(5) Estimated payout ratio assumes a distribution rate of $0.07 per month per Trust Unit for January and February 2009, and a distribution rate of $0.05 per month per Trust Unit for March through December 2009.

Below is a table that shows sensitivities of PET's 2009 estimated funds flow to operational changes and changes in the business environment:

		Impact on funds flow per Trust Unit	
Funds flow sensitivity analysis ($ per Trust Unit)	Change	Annual	Monthly
Business environment			
Natural gas price at AECO	$0.25 per Mcf	0.04	0.003
Interest rate on debt	1%	0.02	0.002
Operational			
Production volume	5 MMcfe/d	0.09	0.008
Operating costs	$0.10 per Mcfe	0.06	0.005
Cash general and administrative expenses	$0.10 per Mcfe	0.06	0.005

PET has a proactive gas price risk management strategy in place that has resulted in significant downside protection for the next two years. For April through December 2009 PET has an average of 100.3 MMcf/d of natural gas production hedged at an average price of $7.74 per Mcf. For January 2010 through March 2011 PET has an average of 96.7 MMcf/d of gas production hedged at an average price of $8.09 per Mcf. The table below presents the impact of the Trust's current financial and physical forward sales portfolio on its projected funds flows for 2009 and future years under several different AECO price assumptions.

	Average AECO monthly index gas price ($/GJ)			
Hedging sensitivities ($ millions)	$4.00	$5.00	$6.00	$7.00
Undiscounted value of 2009 hedges	124	88	52	16
Undiscounted value of post-2009 hedges	170	124	78	31

(1) These are non-GAAP terms; please refer to "Significant accounting policies and non-GAAP measures" in this MD&A.

(2) Amount excludes projected funds flows from the Trust's 2009 financial and physical forward sales portfolio.

The Trust's outlook and sensitivities assume operating costs of $1.88 per Mcfe, cash general and administrative expenses of $0.47 per Mcfe, an interest rate on bank debt of 4.5 percent and incorporate the Trust's financial and physical forward sales portfolio at March 9, 2009. Cash general and administrative expenses are equal to general and administrative expenses before Trust Unit-based compensation.

The current April to December 2009 forward monthly market for natural gas at AECO is $4.78 per Mcf. This equates to a mark-to-market value, primarily in financial swap instruments, of $83 million for the remainder of 2009. The current April 2009 to December 2011 forward monthly price at AECO is $5.53 per Mcf. Including realized gains on financial forward sales contracts for the first three months of 2009, the value of the Trust's natural gas forward sales portfolio is $170 million. Furthermore, approximately 45 percent of the Trust's debt is in the form of convertible term debt, the majority of which matures in 2011 and 2012. The Trust's current hedge portfolio combined with PET's current debt profile provides the Trust with significant financial flexibility in this challenging economic climate.

OTHER SIGNIFICANT ACCOUNTING POLICIES AND NON-GAAP MEASURES

Payout ratio

Payout ratio refers to distributions on Trust Units measured as a percentage of funds flow for the period and is used by management to analyze funds flow available for development and acquisition opportunities as well as overall sustainability of distributions. Funds flow does not have any standardized meaning prescribed by GAAP and therefore payout ratio may not be comparable to the calculation of similar measures for other entities.

Operating and funds flow netbacks

Operating and funds flow netbacks are used by management to analyze margin and funds flow on each Mcf of natural gas production. Operating and funds flow netbacks do not have any standardized meaning as prescribed by GAAP and therefore may not be comparable to the calculation of similar measures for other entities. Operating and funds flow netbacks should not be viewed as an alternative to cash from operating activities, net earnings per Trust Unit or other measures of financial performance calculated in accordance with GAAP.

Revenue, including realized gains (losses) on financial instruments

Revenue, including realized gains (losses) on financial instruments, is used by management to calculate the Trust's net realized natural gas price taking into account monthly settlements on financial forward natural gas sales and foreign exchange contracts. These contracts are put in place to protect PET's funds flows from potential volatility in natural gas prices, and as such any related realized gains or losses are considered part of the Trust's natural gas price. Revenue, including realized gains (losses) on financial instruments does not have any standardized meaning as prescribed by GAAP and should not be reviewed as an alternative to Revenue or other measures calculated in accordance with GAAP.

Net debt

Net debt is measured as bank debt including net working capital (deficiency) excluding short-term financial instrument assets and liabilities related to the Trust's hedging activities and the current portion of convertible debentures. Total net debt includes convertible debentures, measured at principal amount. Net debt and total net debt are used by management to analyze leverage. Net debt and total net debt do not have any standardized meaning prescribed by Canadian GAAP and therefore these terms may not be comparable with the calculation of similar measures for other entities.

Total capitalization

Total capitalization is equal to net debt including convertible debentures plus market value of issued equity and is used by management to analyze leverage. Total capitalization as presented does not have any standardized meaning prescribed by Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

CRITICAL ACCOUNTING ESTIMATES

The MD&A is based on the Trust's consolidated financial statements which have been prepared in Canadian dollars in accordance with GAAP. The application of GAAP requires management to make estimates, judgments and assumptions that affect the reported amounts of assets and liabilities and disclosure of contingent assets and liabilities, if any, at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period. PET bases its estimates on historical experience and various other assumptions that are believed to be reasonable under the circumstances. Actual results could differ from these estimates under different assumptions or conditions.

Following is a discussion of the critical accounting estimates that are inherent in the preparation of the Trust's consolidated financial statements and notes thereto.

Accounting for petroleum and natural gas operations

Under the successful efforts method of accounting, the Trust capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves including acquisitions, successful exploratory wells, development costs and the costs of support equipment and facilities. Exploration expenditures including geological and geophysical costs, lease rentals and exploratory dry holes are charged to earnings in the period incurred. The application of the successful efforts method of accounting requires management's judgment to determine the proper designation of wells as either developmental or exploratory which will ultimately determine the proper accounting treatment of the costs incurred. The results of a drilling operation can take considerable time to analyze and the determination that proved reserves have been discovered requires both judgment and application of industry experience. The evaluation of petroleum and natural gas leasehold acquisition costs requires management's judgment to evaluate the fair value of land in a given area.

Reserve estimates

Estimates of the Trust's reserves included in its consolidated financial statements are prepared in accordance with guidelines established by the Canadian Securities Administrators. Reserve engineering is a subjective process of estimating underground accumulations of petroleum and natural gas that cannot be measured in an exact manner. The process relies on interpretations of available geological, geophysical, engineering and production data. The accuracy of a reserve estimate is a function of the quality and quantity of available data, the interpretation of that data, the accuracy of various mandated economic assumptions and the judgment of the persons preparing the estimate.

PET's reserve information is based on estimates prepared by its independent petroleum consultants. Estimates prepared by others may be different than these estimates. Because these estimates depend on many assumptions, all of which may differ from actual results, reserve estimates may be different from the quantities of petroleum and natural gas that are ultimately recovered. In addition, the results of drilling, testing and production after the date of an estimate may justify revisions to the estimate. The present value of future net revenues should not be assumed to be the current market value of the Trust's estimated reserves. Actual future prices, costs and reserves may be materially higher or lower than the prices, costs and reserves used for the future net revenue calculations. The estimates of reserves impact depletion, dry hole expenses and asset retirement obligations. If reserve estimates decline, the rate at which the Trust records depletion increases thereby reducing net earnings. In addition, changes in reserve estimates may impact the outcome of PET's assessment of its petroleum and natural gas properties for impairment.

Purchase price allocation

Corporate acquisitions are accounted for by the purchase method of accounting whereby the purchase price is allocated to the assets and liabilities acquired based on their fair values as estimated by management at the time of acquisition. The excess of the purchase price over the fair values represents goodwill. In order to estimate fair values, management has to make various assumptions including commodity prices, reserves acquired and discount rates. Differences from these estimates may impact the future financial statements of the Trust.

Impairment of petroleum and natural gas properties

The Trust reviews its proved properties for impairment on an operational field basis. For each property, an impairment provision is recorded whenever events or circumstances indicate that the carrying value of that property may not be recoverable. The impairment provision is based on the excess of carrying value over fair value. Fair value is defined as the present value of the future net revenues from the property as estimated by the Trust on the balance sheet date. Reserve estimates and estimates for natural gas prices and production costs may change and there can be no assurance that impairment provisions will not be required in the future.

Management's assessment of, among other things, the results of exploration activities, commodity price outlooks and planned future development and sales impacts the amount and timing of impairment provisions.

Asset retirement obligations

The asset retirement obligations recorded in the consolidated financial statements are based on an estimate of the fair value of the total costs for future site restoration and abandonment of the Trust's petroleum and natural gas properties. This estimate is based on management's analysis of production structure, reservoir characteristics and depth, market demand for equipment, currently available procedures, the timing of asset retirement expenditures and discussions with construction and engineering consultants. Estimating these future costs requires management to make estimates and judgments that are subject to future revisions based on numerous factors including changing technology and political and regulatory environments. PET engages an independent environmental consulting firm to analyze and prepare an annual estimate of the Trust's asset retirement obligations in accordance with National Instrument 51-101. The asset retirement obligation does not include any adjustment for the net salvage value of tangible equipment and facilities.

NEW ACCOUNTING STANDARDS

The Canadian Institute of Chartered Accountants ("CICA") released new accounting standards for implementation effective January 1, 2008, as follows:

a) Section 3031 – Inventories. The new standard replaces the previous inventories standard and prescribes certain methods for valuing inventories. The adoption of this standard has had no material impact on PET's consolidated financial statements.

b) Section 3862 – Financial Instruments - Disclosures and Section 3863 - Financial Instruments - Presentation. The new disclosure standard requires increased disclosure regarding the Trust's financial instruments, the risks associated with these instruments and how the risks are managed. The new presentation standard carries forward the former presentation requirements. The required disclosures are contained in Notes 1a) and 12 to the Trust's consolidated financial statements.

c) Section 1535 - Capital Disclosures. The new standard requires the Trust to disclose its definition of capital and its objectives, policies and processes for managing its capital structure. The required disclosures are contained in Note 12 to the Trust's consolidated financial statements.

Goodwill and intangible assets

In February 2008, the CICA issued section 3064, "Goodwill and Intangible Assets," which will replace CICA section 3062 of the same name. As a result of issuing this guidance, CICA section 3450, "Research and Development Costs," and Emerging Issues Committee Abstract No. 27, "Revenues and Expenditures during the Pre-Operating Period," will be withdrawn. This new guidance requires recognizing all goodwill and intangible assets in accordance with CICA section 1000, "Financial Statement Concepts." Section 3064 will eliminate the current practice of recognizing items as assets that do not meet the section 1000 definition and recognition criteria.

Business combinations

In December 2008, the CICA issued section 1582 "Business Combinations," which will replace CICA section 1581 of the same name. Under this guidance, the purchase price used in a business combination is based on the fair value of shares exchanged at their market price at the date of the exchange. Currently the purchase price used is based on the market price of the shares for a reasonable period before and after the date the acquisition is agreed upon and announced. This new guidance generally requires all acquisition costs to be expensed, which currently are capitalized as part of the purchase price. Contingent liabilities are to be recognized at fair value at the acquisition date and remeasured at fair value through earnings each period until settled. Currently only contingent liabilities that are resolved and payable are included in the cost to acquire the business. In addition, negative goodwill is required to be recognized immediately in earnings, unlike the current requirement to eliminate it by deducting it from non-current assets in the purchase price allocation. Section 1582 will be effective for PET on January 1, 2011 with prospective application.

INTERNATIONAL FINANCIAL REPORTING STANDARDS ("IFRS")

The Canadian Accounting Standards Board recently confirmed January 1, 2011 as the date IFRS will replace GAAP in Canada for publicly accountable enterprises. PET's first reporting period under IFRS will be interim financial statements for period ended March 31, 2011 and first IFRS annual financial statements for year ended December 31, 2011.

Prior to the implementation date, the Trust intends on completing a detailed financial statement level assessment of the impact of IFRS conversion. During this period, PET will decide on accounting policies permissible under IFRS, which fit the Trust's operations and business strategy. PET intends to proceed with integration of the selected accounting policies for the opening balance sheet on January 1, 2010, which will be used for comparative purposes once the IFRS conversion is effective January 1, 2011.

The Trust has identified key internal personnel with expertise to manage its transition to IFRS. During 2008, PET staff were involved in external IFRS training and development by means of attending conferences, participating in special interest seminars, and focusing on numerous training sessions put on by various accounting service firms. During 2008 PET personnel have also initiated a detailed review of IFRS standards and other guidance in order to identify potential differences between current IFRS and current Canadian GAAP, as well as potential differences that may arise due to proposed changes in IFRS or Canadian GAAP prior to the 2011 transition date. To date potentially significant differences between IFRS and Canadian GAAP have been identified in the accounting for long-term assets, including exploration and evaluation of petroleum and natural gas properties, depletion and impairment. Further differences may be identified as PET continues its review of IFRS standards in 2009 and 2010.

PET will actively monitor the effects of the IFRS conversion on information technology systems and internal controls over financial reporting.

RISK FACTORS

PET's operations are affected by a number of underlying risks, both internal and external to the Trust. These risks are similar to those affecting others in both the conventional oil and gas royalty trust sector and the conventional oil and gas producers sector. The Trust's financial position, results of operations, and cash available for distribution to Unitholders are directly impacted by these factors.

Global financial crisis

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.

Petroleum 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.

Income taxes

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 have 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 market 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.

Gas over bitumen issue

Decisions by the Alberta Energy and Utilities Board ("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 in previous years.

On July 24, 2007 the AEUB released Decision 2007-056 related to the application for shut-in of certain natural gas production in the Cold Lake area in northeast Alberta. Although PET does not produce natural gas from the formations of concern in the area identified in Decision 2007-056, the AEUB did note in its conclusions that a broad bitumen conservation strategy may be required for all areas where natural gas production may interfere with eventual bitumen recovery. In 2007 the AEUB was reorganized and responsibility for oil and natural gas industry regulation was transferred to the newly created Energy Resources Conservation Board ("ERCB"). 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.

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 Unitholder

Depletion of reserves

The Trust has certain unique attributes which differentiate it from other oil and gas industry participants. Distributions, absent commodity price increases or cost effective acquisition and development activities, will decline over time in a manner consistent with declining production from typical oil and natural gas reserves. PET will not be reinvesting cash flow in the same manner as other industry participants as one of the main objectives of the Trust is to maximize long-term distributions. Accordingly, absent capital injections, PET's initial production levels and reserves will decline.

PET's future oil and natural gas reserves and production, and therefore its funds flows, will be highly dependent on PET's success in exploiting its reserve base and acquiring additional reserves. Without reserves additions through acquisition or development activities, the Trust's reserves and production will decline over time as reserves are exploited.

To the extent that external sources of capital including the issuance of additional Trust Units become limited or unavailable PET's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that PET is required to use funds flow to finance capital expenditures or property acquisitions, the level of distributions will be reduced.

PET reinvests capital to minimize the effects of natural production decline on its asset base. The Trust currently estimates that capital expenditures of $100 million to $130 million annually are required to maintain production at current levels. There can be no assurance that PET will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Reserve estimates

Estimates of PET's natural gas reserves depend in large part upon the reliability of available geological and engineering data. Geological and engineering data are used to determine the probability that a reservoir of natural gas exists at a particular location and whether, and the extent to which, natural gas is recoverable from a reservoir. The reliability of reserve estimates depends on:

- whether the prevailing tax rules and other government regulations will remain the same as on the date estimates are made;
- whether existing contracts remain the same as on the date estimates are made;
- whether natural gas and other prices will remain the same as on the date estimates are made;
- the production performance of our reservoirs;
- extensive engineering judgments;
- the price at which recovered natural gas can be sold;
- the costs associated with recovering natural gas;
- the prevailing environmental conditions associated with drilling and production sites;
- the availability of enhanced recovery techniques; and
- the ability to transport natural gas to markets.

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.

Cyclical and seasonal impact on industry

The Trust's 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 regions. Any decline in natural gas prices could have an adverse effect on the Trust's financial condition.

Operational matters

The Trust's operations may be delayed or unsuccessful for many reasons including cost overruns, lower natural gas prices, equipment shortages, mechanical and technical difficulties and labour problems. The Trust's operations will also often require the use of new and advanced technologies which can be expensive to develop, purchase and implement and may not function as expected. PET may experience substantial cost overruns caused by changes in the scope and magnitude of our operations, employee strikes and unforeseen technical problems including natural hazards which may result in blowouts, environmental damage or other unexpected or dangerous conditions giving rise to liability to third parties. In particular, drilling activities are subject to many risks, including the risk that no commercially productive reservoirs will be encountered. Drilling for natural gas could result in unprofitable efforts, not only from dry wells but from wells that are productive but do not produce enough net revenue to return a profit after drilling, operating and other costs. The costs of drilling, completing and operating wells are often uncertain. In addition, our operations depend on the availability of drilling and related equipment in the particular areas where exploration and development activities will be conducted. Demand for the equipment or access restrictions may affect the availability of that equipment and, consequently, delay operations.

Continuing production from a property, and to some extent marketing of production there from, is largely dependent upon economic variables and the ability of the operator of the property. Operating costs on most properties have increased significantly over recent years. To the extent the operator fails to perform these functions properly, revenue may be reduced. Payments from production generally flow through the operator and there is a risk of delay and additional expense in receiving such revenues if the operator becomes insolvent. Although satisfactory title reviews are generally conducted in accordance with industry standards, such reviews do not guarantee or certify that a defect in the chain of title may not arise to defeat the claim of the Trust to certain properties. A reduction in distributions on Trust Units could result in such circumstances.

Expansion of operations

The operations and expertise of management of the Trust are currently focused on natural gas production and development in the Western Canadian Sedimentary Basin. In the future, the Trust 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.

Acquisitions

The price paid for asset acquisitions is based on the Trust's internal assessment of the reserves and future production potential adjusted for risk. These assessments include a number of material assumptions regarding such factors as recoverability and marketability of oil and natural gas, future prices of oil and natural gas, and operating costs, future capital expenditures and royalties and other government levies which will be imposed over the producing life of the reserves. Many of these factors are subject to change and are beyond the control of the operators of the working interests, management and the Trust. In particular, changes in prices of and markets for petroleum and natural gas from those anticipated at the time of making such assessments will affect the amount of future distributions and as such the value of the Trust Units. In addition, all such estimates involve a measure of geological and engineering uncertainty which could result in lower production and reserves than attributed to the working interests. Actual reserves could vary materially from these estimates. Consequently, the reserves acquired may be less than expected, which could adversely impact funds flows and distributions to Unitholders.

Debt service

Amounts paid in respect of interest and principal on debt will reduce distributions. Variations in interest rates and scheduled principal repayments could result in significant changes in the amount required to be applied to debt service before payment of distributions. Certain covenants of the agreements with PET's lenders may also limit distributions. Although PET believes the credit facilities will be sufficient for the Trust's immediate requirements, there can be no assurance that the amount will be adequate for the future financial obligations of the Trust or that additional funds will be able to be obtained.

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

Net asset value

The net asset value of the assets of the Trust will vary from time to time dependent upon a number of factors beyond the control of management, including oil and natural gas prices. The trading prices of the Trust Units from time to time are also determined by a number of factors that are beyond the control of management and such trading prices may vary from the net asset value of the Trust's assets.

Insurance risk

Exploration for natural gas and the production of natural gas are hazardous undertakings. Natural disasters, operator error or other occurrences can result in oil spills, blowouts, cratering, fires, equipment failure and loss of well control which can injure or kill people, damage or destroy wells and production facilities and damage other property and the environment. Losses and liabilities arising from such events could significantly reduce the Trust's revenues or increase costs and have a material adverse effect on the Trust's operations or financial condition.

PET may be unable to obtain insurance against these risks at premium levels that justify its purchase. Further, insurance may be unavailable or any insurance we may obtain may be insufficient to provide full coverage. The occurrence of a significant event that is not fully insured could have a material adverse effect on PET's financial position and reduce or eliminate distributions to Unitholders.

Additional financing

PET's primary source of bank financing is a demand credit facility with a syndicate of Canadian chartered banks in the amount of $400 million. The revolving nature of the credit facility is presently due to expire on May 25, 2009. PET expects that the facility will be extended at that date. If the facility is not extended it will be subject to a one year term-out provision and the Trust will need to find alternative sources of financing. In addition the credit facility is subject to semi-annual borrowing base redeterminations. The lenders' assessments of the lending value attributable to PET's reserves may limit the amount available under the facility. If alternative sources of financing are not available, or are more expensive than the current credit facility, PET may be unable to effectively operate its business or pay distributions to Unitholders.

In the normal course of making capital investments to maintain and expand the oil and natural gas reserves of the Trust, additional Trust Units are issued from treasury which may result in a decline in production per Trust Unit and reserves per Trust Unit. Additionally, from time to time the Trust issues Trust Units from treasury in order to reduce debt and maintain a more optimal capital structure. Conversely, to the extent that external sources of capital, including the issuance of additional Trust Units, become limited or unavailable, the Trust's ability to make the necessary capital investments to maintain or expand its oil and natural gas reserves will be impaired. To the extent that PET is required to use funds flow to finance capital expenditures or property acquisitions, to pay debt services charges or to reduce debt, distributions will be reduced.

Financial instruments

The nature of PET's operations results in exposure to fluctuations in commodity prices. The Trust will monitor and, when appropriate, utilize derivative financial instruments and physical delivery contracts to mitigate its exposure to these risks. PET may be exposed to credit-related losses in the event of non-performance by counter-parties to the financial instruments. From time to time the Trust may enter into risk management activities in an effort to mitigate the potential impact of declines in natural gas prices. These activities may consist of, but are not limited to:

- buying a price floor under which the Trust will receive a minimum price for natural gas production;
- buying a collar under which the Trust will receive a price within a specified price range for natural gas production;
- selling call options to third parties, giving them the right to purchase natural gas from the Trust at a specified price in future periods in exchange for an upfront cash payment to PET;
- entering into fixed price contract for natural gas production; and
- entering into contracts to fix the basis differential between natural gas markets.

If product prices increase above the levels specified in PET's various hedging agreements, the Trust would be precluded from receiving the full benefit of commodity price increases.

In addition, by entering into these hedging activities the Trust may suffer financial loss if:

- PET is unable to produce sufficient quantities of natural gas to fulfill its obligations;
- PET is required to pay a margin call on a financial hedge contract; or
- PET is required to pay royalties based on a market or reference price that is higher than its hedged fixed or ceiling price.

Non-resident ownership of Trust Units

In order for the Trust to maintain its status as a mutual fund trust under the Income Tax Act, the Trust intends to comply with the requirements of the Income Tax Act for "mutual fund trusts" at all relevant times. In this regard, the Trust shall among other things, monitor the ownership of the Trust Units to carry out such intentions. The Trust Indenture provides that if at any time the Trust becomes aware that the beneficial owners of 48 percent or more of the Trust Units then outstanding may be non-residents or that such a situation is imminent, the Trust shall take such actions as may be necessary to carry out the foregoing intention.

Accounting write-downs as a result of GAAP

GAAP requires that management apply certain accounting policies and make certain estimates and assumptions that affect reported amounts in the consolidated financial statements of the Trust. 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 unfavorably 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 including unproved properties, 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.

Renegotiation or termination of contracts

As at the date hereof, the Trust does not anticipate that any aspect of its business will be materially affected in the current fiscal year by the renegotiation or termination of contracts or subcontracts.

Competitive conditions

The Trust is a member of the petroleum industry which is highly competitive at all levels. The Trust competes with other companies and other energy trusts for all of its business inputs including exploitation and development prospects, access to commodity markets, property and corporate acquisitions, and available capital. The Trust endeavours to be competitive by maintaining a strong financial condition through attracting and retaining technically competent and accountable staff, by refining and enhancing business processes on an ongoing basis and by utilizing current technologies to enhance exploitation, development and operational activities.

Environmental considerations

Compliance with health, safety and environmental laws and regulations could materially increase the Trust's costs. PET will incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. These include costs to reduce certain types of air emissions and discharges and to remediate contamination at various facilities and third party sites where the Trust's products or wastes will be handled or disposed.

PET is subject to statutory strict liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of the Trust's licenses. As a result, anyone who suffers losses or damages as a result of pollution caused by PET's operations can claim compensation without needing to demonstrate that the damage is due to any fault on the Trust's part.

New laws and regulations, tougher requirements in licensing, increasingly strict enforcement of, or new interpretations of, existing laws and regulations and the discovery of previously unknown contamination may require future expenditures to:

- modify operations;
- install pollution control equipment;
- perform site clean-ups; or
- curtail or cease certain operations.

In addition, increasingly strict environmental requirements may affect product specifications and operational practices. Future expenditures to meet such specifications could have a material adverse effect on the Trust's operations or financial condition. Any abandonment costs PET incurs will reduce cash available for distribution to Unitholders and other uses.

The Trust is proactive in its approach to environmental concerns. Procedures are in place to ensure that due care is taken in the day-to-day management of its properties. All government regulations and procedures are followed in adherence to the law. The Trust believes in well abandonment and site restoration in a timely manner to ensure minimal damage to the environment and lower overall costs to the Trust.

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 so-called "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. 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.

Government regulation risk

PET operates in a highly regulated industry and it is possible any changes in such regulation or adverse regulatory decisions could affect our production which could reduce distributions to Unitholders. Additional details with respect to the gas over bitumen regulatory issue are described elsewhere in this MD&A.

Commodity price, foreign exchange and interest rate risk

The two most important factors affecting the level of cash available for distribution to Unitholders are the level of production achieved by PET, and the price received for its production. These prices are influenced in varying degrees by factors outside the Trust's control. Some of these factors include:

- economic conditions which influence the demand for natural gas and the level of interest rates set by the governments of Canada and the U.S.;
- weather conditions that influence the demand for natural gas;
- transportation availability and costs; and
- price differentials among markets based on transportation costs to major markets.

To mitigate these risks, PET has an active gas price risk management program in place based on an established set of criteria that has been approved by the Board of Directors of the Administrator. The results of this program are reviewed against these criteria and the results actively monitored by the Board.

Beyond our price risk management strategy, PET also mitigates risk by having a diversified gas marketing portfolio and by transacting with a number of counter-parties and limiting exposure to each counter-party.

The contracts that PET has with aggregators of natural gas vary in length. They represent a blend of domestic markets with fixed and floating prices designed to provide price diversification to our revenue stream.

PET is also subject to interest rate risk to the extent its credit facility bears interest at a floating rate based on the lender's prime rate, and foreign exchange rate risk as a portion of the Trust's gas sales are on NYMEX and therefore denominated in US dollars. The Trust mitigates interest rate risk by having a portion of its overall debt in convertible debentures, which bear a fixed interest rate. PET may enter into financial forward foreign exchange contracts in order to limit exposure to US dollar sales from time to time, as the Trust considers appropriate.

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.

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 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.

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.

Nature of Trust Units

The Trust Units do not represent a traditional investment in the oil and natural gas sector and should not be viewed by investors as shares in a corporation. The Trust Units represent a fractional interest in the Trust. As holders of Trust Units, Unitholders will not have the statutory rights normally associated with ownership of shares of a corporation. The Trust's sole assets will be royalty interests in the Trust's properties. The price per Trust Unit is a function of anticipated distributable income, the properties acquired by PET and PET's ability to effect long-term growth in the value of the Trust. The market price of the Trust Units will be sensitive to a variety of market conditions including, but not limited to, interest rates and the ability of the Trust to acquire oil and natural gas properties. Changes in market conditions may adversely affect the trading prices of the Trust Units.

FORWARD-LOOKING INFORMATION

This MD&A contains forward-looking information with respect to PET.

The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. 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 our forward-looking statements. We believe the expectations reflected in these forward-looking statements are reasonable. However, we cannot assure the reader that these expectations will prove to be correct. The reader should not unduly rely on forward-looking statements included in this report. These statements speak only as of the date of the MD&A.

In particular, this MD&A contains forward-looking statements pertaining to the following:

- the quantity and recoverability of PET's reserves;
- the timing and amount of future production;
- prices for natural gas produced;
- operating and other costs;
- business strategies and plans of management;
- supply and demand for natural gas;
- expectations regarding PET's access to capital to fund its acquisition exploration and development activities;

- the disposition swap, farm in, farm out or investment in certain exploration properties using third party resources;
- the use of exploration and development activity and acquisitions to replace and add to reserves;
- the impact of changes in natural gas prices on funds flow after hedging;
- drilling, completion, facilities and construction plans;
- the existence, operations and strategy of the commodity price risk management program;
- the approximate and maximum amount of forward sales and hedging to be employed;
- the Trust's acquisition strategy, the criteria to be considered in connection therewith and the benefits to be derived there from;
- the impact of Canadian federal and provincial governmental regulation on the Trust relative to other issuers;
- PET's treatment under governmental regulatory regimes;
- the goal to sustain or grow production and reserves through prudent asset management and acquisitions;
- the emergence of accretive growth opportunities; and
- PET's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets.

PET's actual results could differ materially from those anticipated in these forward-looking statements as a result of the risk factors set forth below and elsewhere in this MD&A which include but are not limited to:

- volatility in market prices for natural gas;
- risks inherent in PET's operations;
- uncertainties associated with estimating reserves;
- competition for, among other things; capital, acquisitions of reserves, undeveloped lands, skilled personnel, equipment for drilling, completions, facilities and pipeline construction and maintenance;
- incorrect assessments of the value of acquisitions;
- geological, technical, drilling and process problems;
- general economic conditions in Canada, the United States and globally;
- industry conditions including fluctuations in the price of natural gas;
- royalties payable in respect of PET's production;
- governmental regulation of the oil and gas industry, including environmental regulation;
- fluctuation in foreign exchange or interest rates;
- unanticipated operating events that can reduce production or cause production to be shut-in or delayed;
- stock market volatility and market valuations; and
- the need to obtain required approvals from regulatory authorities.

The above list of risk factors should not be construed as exhaustive.

Additional information on PET, including the most recent filed Annual Report and Annual Information Form, can be accessed at www.sedar.com or from the Trust's website at www.paramountenergy.com.

MANAGEMENT'S REPORT

The consolidated financial statements of PET are the responsibility of Management and have been approved by the Board of Directors of the administrator of PET. These consolidated financial statements have been prepared by Management in accordance with generally accepted accounting principles (GAAP) in Canada and include amounts that are based on estimates and judgments.

Management has prepared Management's Discussion and Analysis which is based on PET's financial results prepared in accordance with Canadian GAAP. It compares PET's financial performance in 2008 to 2007 and should be read in conjunction with the consolidated financial statements and accompanying notes.

Management is responsible for establishing and maintaining adequate internal control over PET's financial reporting. Management believes that the system of internal controls that have been designed and maintained at PET provide reasonable assurance that financial records are reliable and form a proper basis for preparation of financial statements. The internal accounting control process includes Management's communication to employees of policies which govern ethical business conduct.

Under the supervision and with the participation of the Chief Executive Officer and Chief Financial Officer, Management conducted an evaluation of the effectiveness of its internal control over financial reporting based on the framework in Internal Control – Integrated Framework issued by the Committee of Sponsoring Organizations of the Treadway Commission (COSO). Based on this assessment according to these criteria, Management concluded that internal control over financial reporting is effective as of December 31, 2008 and 2007 to provide reasonable assurance regarding the reliability of financial reporting and the preparation of financial statements for external reporting purposes in accordance with GAAP.

Internal control systems, no matter how well designed, have inherent limitations. Therefore, even those systems determined to be effective can provide only reasonable assurance with respect to financial statement preparation and presentation. Also, projections of any evaluation of effectiveness to future periods are subject to the risk that controls may become inadequate because of changes in conditions, or that the degree of compliance with the policies or procedures may deteriorate.

The Board of Directors has appointed an Audit Committee consisting of unrelated, non-management directors which meets at least four times during the year with Management and independently with the external auditors and as a group to review any significant accounting, internal control and auditing matters in accordance with the terms of the charter of the Audit Committee as set out in the Annual Information Form. The Audit Committee reviews the consolidated financial statements and Management's Discussion and Analysis before the consolidated financial statements are submitted to the Board of Directors for approval. The external auditors have free access to the Audit Committee without obtaining prior Management approval.

With respect to the external auditors, KPMG LLP, the Audit Committee approves the terms of engagement and reviews the annual audit plan, the Auditors' Report and results of the audit. It also recommends to the Board of Directors the firm of external auditors to be appointed by the unitholders.

The independent external auditors, KPMG LLP, have been appointed by the Board of Directors on behalf of the unitholders to express an opinion as to whether the consolidated financial statements present fairly, in all material respects, the Company's financial position, results of operations and cash flows in accordance with Canadian GAAP. The report of KPMG LLP outlines the scope of their examination and their opinion on the consolidated financial statements.

Susan Riddell Rose

Susan L. Riddell Rose

President
Chief Executive Officer

Cameron R. Sebastian

Vice President, Finance &
Chief Financial Officer

March 6, 2009

AUDITORS' REPORT

To the Unitholders of Paramount Energy Trust

We have audited the consolidated balance sheets of Paramount Energy Trust ("PET") as at December 31, 2008 and 2007 and the consolidated statements of earnings (loss) and deficit and cash flows for each of the years then ended. These financial statements are the responsibility of PET's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with Canadian generally accepted auditing standards and in accordance with the standards of the Public Company Accounting Oversight Board (United States). Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material mis-statement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the finan-cial statements. An audit also includes assessing the accounting principles used and significant estimates made by man-agement, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of PET as at December 31, 2008 and 2007 and the results of its operations and its cash flows for the years then ended in accordance with Canadian generally accepted accounting principles.

KPMG LLP

KPMG LLP

Chartered Accountants

Calgary, Canada

March 6, 2009

CONSOLIDATED BALANCE SHEETS

As at	December 31, 2008	December 31, 2007
($ thousands)		
Assets		
Current assets		
Accounts receivable	**$ 63,612**	$ 65,160
Marketable securities (note 3)	**127**	1,069
Financial instruments (notes 2 and 12)	**45,262**	18,447
	109,001	84,676
Property, plant and equipment (notes 4 and 5)	**954,153**	1,097,338
Goodwill	**29,129**	29,129
Financial instruments (notes 2 and 12)	**13,406**	1,564
	$ 1,105,689	$ 1,212,707
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 50,473**	$ 48,754
Distributions payable	**11,297**	10,956
Bank debt (note 7)	**9,828**	-
Convertible debentures (note 8)	**5,848**	-
	77,446	59,710
Long term bank debt (note 7)	**276,976**	342,190
Gas over bitumen royalty adjustments (note 15)	**74,643**	59,593
Asset retirement obligations (note 11)	**179,723**	194,132
Convertible debentures (note 8)	**221,518**	224,135
Future income taxes (note 14)	**16,086**	–
Non-controlling interest (note 6)	**1,871**	2,012
Unitholders' equity		
Unitholders' capital (note 9)	**1,108,453**	1,083,250
Equity component of convertible debentures (note 8)	**7,335**	7,338
Contributed surplus (note 10)	**12,873**	8,446
Deficit	**(871,235)**	(768,099)
	257,426	330,935
	$ 1,105,689	$ 1,212,707

See accompanying notes

Basis of presentation: note 1

Commitments and contingencies: notes 12, 13 and 15

Robert A. Maitland
Director

John W. Peltier
Director

CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) AND DEFICIT

	Year ended December 31	
	2008	2007
($ thousands except per Unit amounts)		
Revenue		
Oil and natural gas	**$ 543,576**	$ 412,571
Royalties	**(92,260)**	(64,854)
Realized gain on financial instruments (notes 2 and 12)	**(1,283)**	49,838
Unrealized gain (loss) on financial instruments (notes 2 and 12)	**42,065**	(35,438)
Gas over bitumen revenue (note 15)	**5,702**	3,064
	497,800	365,181
Expenses		
Operating	**120,611**	102,639
Transportation costs	**14,082**	12,716
Exploration expenses (note 4)	**34,118**	18,793
General and administrative (note 10)	**37,626**	28,957
Interest and other	**13,822**	21,357
Interest on convertible debentures	**18,345**	15,567
Gain on sale of property, plant and equipment (note 4)	**(6,025)**	(21,960)
Depletion, depreciation and accretion	**218,542**	220,168
	451,121	398,237
Earnings (loss) before income taxes	**46,679**	(33,056)
Future income tax (note 14)	**16,086**	-
Current taxes	**-**	-
	-	-
Net earnings (loss) before non-controlling interest	**30,593**	(33,056)
Non-controlling interest (note 6)	**192**	197
Net earnings (loss)	**30,785**	(32,859)
Deficit, beginning of year	**(768,099)**	(619,748)
Change in accounting policy (note 2)	**-**	30,337
Distributions declared	**(133,921)**	(145,829)
Deficit, end of year	**(871,235)**	(768,099)
Accumulated other comprehensive income	**-**	-
Deficit and accumulated other comprehensive income, end of the year	**$ (871,235)**	$ (768,099)
Earnings (loss) per Trust Unit (note 9(c))		
Basic and diluted	**$ 0.28**	$ (0.33)
Diluted	**$ 0.27**	$ (0.33)
Distributions per Trust Unit	**$ 1.20**	$ 1.50

See accompanying notes

CONSOLIDATED STATEMENTS OF CASH FLOWS

	Year ended December 31	
	2008	2007
($ thousands)		
Cash provided by (used for)		
Operating activities		
Net earnings (loss)	**$ 30,785**	$ (32,859)
Items not involving cash		
Depletion, depreciation and accretion	**218,542**	220,168
Trust Unit-based compensation	**5,671**	4,287
Unrealized loss (gain) on financial instruments	**(38,657)**	35,438
Gain on sale of property, plant and equipment	**(6,025)**	(21,960)
Future income taxes	**16,086**	–
Non-cash interest expense on convertible debentures	**3,302**	2,804
Loss on marketable securities	**172**	1,930
Non-controlling interest	**(192)**	(197)
Exploration expense	**21,522**	4,216
Gas over bitumen royalty adjustments	**15,050**	14,239
Expenditures on asset retirement obligations	**(5,226)**	(2,597)
Change in non-cash working capital	**(1,266)**	(2,532)
Cash flow provided by operating activities	**259,764**	222,937
Financing activities		
Issue of Trust Units	**4,031**	248,996
Distributions to Unitholders	**(114,067)**	(125,374)
Issue of convertible debentures	**-**	72,000
Change in bank debt	**(55,386)**	119,267
Change in mortgage	**-**	(5,734)
Change in non-cash working capital	**(1,614)**	(7,747)
	(167,036)	301,408
	$ 92,728	$ 524,345
Investing activities		
Acquisition of properties and corporate assets	**(7,294)**	(451,830)
Exploration and development expenditures	**(116,913)**	(106,924)
Proceeds on sale of property and equipment	**24,220**	46,408
Proceeds on sale of investment	**770**	-
Change in non-cash working capital	**6,489**	(11,999)
	$ (92,728)	$ (524,345)
Change in cash	**-**	-
Cash, beginning of year	**-**	-
Cash, end of year	**$ -**	$ -
Interest paid	**$ 28,764**	$ 32,804
Taxes paid	**-**	-

See accompanying notes

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

(dollar amounts in $ thousands Cdn except as noted)

1. BASIS OF PRESENTATION AND ACCOUNTING POLICIES

Paramount Energy Trust ("PET" or the "Trust") is an unincorporated trust formed under the laws of the Province of Alberta pursuant to a trust indenture ("PET Trust Indenture") dated June 28, 2002. The beneficiaries of PET are the holders of the Trust Units ("Trust Units" or "Units") of PET (the "Unitholders"). PET was established for the purposes of issuing Trust Units and acquiring and holding royalties and other investments. The consolidated financial statements of PET consist of 100 percent ownership of Paramount Energy Operating Corp. (the "Administrator") and the beneficial interests of Paramount Operating Trust ("POT"). PET utilizes a calendar fiscal year for financial reporting purposes.

The Administrator was incorporated primarily to act as trustee of POT. As trustee of POT, the Administrator will hold legal title to the properties and assets of POT on behalf of and for the benefit of POT and will administer, manage and operate the oil and gas business of POT. In addition, the Administrator provides certain management and administrative services for PET and its trustee pursuant to a delegation of power and authority to it under the PET Trust Indenture.

The accompanying financial statements have been prepared by management of the Administrator (as agent for the trustee of PET) on behalf of PET in accordance with Canadian generally accepted accounting principles ("Canadian GAAP").

a) Principles of consolidation The consolidated financial statements include the accounts of the Trust and its subsidiaries, all of which are wholly-owned with the exception of Severo Energy Corporation (see note 6).

b) Petroleum and natural gas operations PET follows the successful efforts method of accounting for petroleum and natural gas operations. Under this method, PET capitalizes only those costs that result directly in the discovery of petroleum and natural gas reserves. Exploration expenses, including geological and geophysical costs, lease rentals and exploratory dry hole costs, are charged to earnings as incurred. Leasehold acquisition costs, including costs of drilling and equipping successful wells, are capitalized. The net cost of unproductive wells, abandoned wells and surrendered leases are charged to earnings in the year of abandonment or surrender.

Depletion and depreciation of petroleum and natural gas properties, including well development expenditures, production equipment, gas plants and gathering systems, are provided on the unit-of-production method based on estimated proved developed reserves of operational fields. Depletion and depreciation of acquisition costs are based on estimated total proved reserves of operational fields.

The net amount at which petroleum and natural gas costs on an operational field are carried is subject to a cost-recovery test annually or as economic events dictate. An impairment loss is recognized when the carrying amount of the asset is greater than the sum of the expected undiscounted future cash flows. The amount of the impairment loss is measured as the difference between the carrying amount and the fair value. The carrying values of capital assets, including the costs of acquiring proved and probable reserves are subject to uncertainty associated with the quantity of oil and gas reserves, future production rates, commodity prices and other factors.

Many of the exploration, development and production activities of the Trust are conducted jointly with others. These financial statements reflect only the Trust's proportionate interest in such activities.

The Trust's corporate assets are recorded at cost and are depreciated on a straight line basis at rates ranging from five percent to 33 percent.

c) Asset retirement obligations The Trust recognizes the fair value of an asset retirement obligation ("ARO") in the period in which it is incurred when a reasonable estimate of the fair value can be made. The fair value of the estimated ARO is recorded as a long-term liability, with a corresponding increase in the carrying amount of the property, plant and equipment. The liability amount is increased each reporting period due to the passage of time, and the amount of accretion is charged to earnings in the period. Revisions to the estimated timing of cash flows or to the original estimated undiscounted cost would also result in an increase or decrease to the ARO, with a corresponding increase/decrease in the carrying amount of property, plant and equipment. Actual costs incurred upon settlement of the ARO are charged against the ARO to the extent of the liability recorded. Any difference between the actual costs incurred upon settlement of the ARO and the recorded liability is recognized as a gain or loss in the Trust's earnings in the period in which the settlement occurs.

d) Foreign currency translation Monetary assets and liabilities denominated in a foreign currency are translated at the rate of exchange in effect at year end while non-monetary assets and liabilities are translated at historical rates of exchange. Revenues and expenses are translated at monthly average rates of exchange. Translation gains and losses are reflected in earnings in the period in which they arise.

e) Financial instruments The Trust uses financial instruments and non-financial derivatives, such as fixed-price commodity sales contracts requiring physical delivery of the underlying commodity, to manage the price risk attributable to anticipated sale of petroleum and natural gas production. The fair values, taking credit risk into consideration, of these financial instruments and non-financial derivatives are recorded as assets or liabilities on the Trust's balance sheet, with changes in fair values from period to period being recorded as unrealized gains (losses) on financial instruments in PET's statement of earnings (loss).

The net receipts or payments arising from financial instruments are recognized in earnings as realized gains/(losses) on financial instruments when paid or received; payments or receipts related to non-financial derivatives are included in revenues in the corresponding period.

f) Income taxes PET, and its principal operating entity POT, are taxable entities under the Income Tax Act (Canada) and are currently taxable only on income that is not distributed or distributable to the Unitholders. Effective January 1, 2011, the Trust will no longer be able to deduct distributions to Unitholders in determining taxable income (see note 14). The Administrator has no tax balances.

PET and its subsidiaries follow the tax liability method of accounting for income taxes. Under this method, income tax liabilities and assets are recognized for the estimated tax consequences attributable to differences between the amounts reported in the financial statements and their respective tax bases, using enacted or substantively enacted income tax rates. The effect of a change in income tax rates on future income tax liabilities and assets is recognized in income in the period that the change occurs.

g) Incentive plans PET has a Unit Incentive Plan and a Bonus Rights Plan as described in note 10. Incentive Rights granted under the Unit Incentive Plan are accounted for using the fair-value based method and expensed over the estimated life of the Incentive Rights. Upon the exercise of the rights, consideration received, together with the amount previously recognized in contributed surplus, is recorded as an increase to Unitholders' capital.

Rights granted under the Bonus Rights Plan are charged to earnings in the period they vest, with a corresponding increase to contributed surplus for any vested but unexercised bonus rights.

h) **Measurement uncertainty** The preparation of financial statements in conformity with Canadian GAAP requires management to make estimates and assumptions that affect the reported amounts of assets and liabilities at the date of the financial statements and the reported amounts of revenues and expenses during the reporting period.

The amounts recorded for depletion, depreciation and accretion are based on estimates prepared by PET's independent reserves evaluators. The asset impairment test calculation is based on estimates of reserves, production rates, oil and natural gas prices, future costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and may impact the consolidated financial statements of future periods.

i) **Revenue recognition** Revenues associated with the sale of natural gas, crude oil, and natural gas liquids are recognized when title passes from the Trust to its customers.

j) **Goodwill** Goodwill is recorded upon a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. The goodwill balance is not amortized but instead is assessed for impairment annually, or more frequently, if events or changes in circumstances indicate that the asset might be impaired. An initial assessment is made by comparing the fair value of the operations, which includes goodwill, to the book values of each reporting unit. If this fair value is less than book value, an impairment is indicated and a second test is performed to measure the amount of the impairment. In the second test, the implied fair value of the goodwill is calculated by deducting the fair value of all tangible and intangible net assets of the reporting unit from the fair value determined in the initial assessment. If the carrying value of the goodwill exceeds the calculated implied fair value of the goodwill, an impairment charge is recorded.

k) **Gas over bitumen royalty adjustments** The majority of royalty adjustments received are recorded as a liability as PET cannot determine if, when or to what extent the royalty adjustment may be repayable through incremental royalties if and when gas production recommences. Therefore, these royalty adjustments will be included in earnings when such determination can be made. For certain wells which have been sold to a third party, the Trust continues to receive the gas over bitumen royalty adjustments although the ownership of the natural gas reserves and responsibility for paying royalties on future production have been transferred to the buyer. Adjustments received for these wells are recorded as revenue.

l) **Convertible debentures** The Trust's convertible debentures are classified as debt with a portion of the proceeds allocated to equity representing the value of the conversion feature. As the debentures are converted, a portion of debt and equity amounts are transferred to Unitholders' capital. The debt balance associated with the convertible debentures accretes over time to the amount owing on maturity and such increases in the debt balance are reflected as non-cash interest expense in the statement of earnings. The convertible debentures are carried net of issue costs on the balance sheet. The issue costs are amortized to earnings using the effective interest rate method.

m) **Marketable securities** The Trust accounts for its marketable securities as financial assets held for trading. As such, the securities are marked to fair value at each balance sheet date using quoted market prices. Changes in the fair value of securities are charged to earnings in the period in which the change occurs.

n) **New accounting pronouncements**

Goodwill and Intangible Assets

In February 2008, the Canadian Institute of Chartered Accountants ("CICA") issued CICA section 3064, "Goodwill and Intangible Assets," which will replace CICA section 3062 of the same name. As a result of issuing this guidance, CICA section 3450, "Research and Development Costs," and Emerging Issues Committee Abstract No. 27, "Revenues and Expenditures during the Pre-Operating Period," will be withdrawn. This new guidance requires recognizing all goodwill and intangible assets in accordance with CICA section 1000, "Financial Statement Concepts." Section 3064 will eliminate the current practice of recognizing items as assets that do not meet the section 1000 definition and recognition criteria.

Business Combinations, Consolidated Financial Statements and Non-Controlling Interests

CICA Handbook Section 1582 ''Business Combinations'' is effective for business combinations with an acquisition date after January 1, 2011. This standard was amended to require additional use of fair value measurements, recognition of additional assets and liabilities, and increased disclosure. Adopting this standard is expected to have a material effect on the way the Trust accounts for future business combinations. Entities adopting Section 1582 will also be required to adopt CICA Handbook Sections 1601 ''Consolidated Financial Statements'' and 1602 ''Non-Controlling Interests''. These standards will require a change in the measurement of non-controlling interest and will require the change to be presented as part of unitholders' equity on the balance sheet. In addition, the income statement of the controlling parent will include 100 per cent of the subsidiary's results and present the allocation between the controlling interest and non-controlling interest. These standards will be effective January 1, 2011, with early adoption permitted. The changes resulting from adopting Section 1582 will be applied prospectively and the changes from adopting Sections 1601 and 1602 will be applied retrospectively.

International Financial Reporting Standards

In January 2006, the Canadian Accounting Standards Board ("AcSB") adopted a strategic plan for the direction of accounting standards in Canada. In February 2008, as part of its strategic plan, the AcSB confirmed that Canadian publicly accountable entities will be required to report under International Financial Reporting Standards ("IFRS"), which will replace Canadian GAAP for years beginning on or after January 1, 2011. An omnibus exposure draft was issued by the AcSB in the second quarter of 2008, which incorporates IFRS into the CICA Handbook and prescribes the transitional provisions for adopting IFRS. The Trust has initiated the diagnostic assessment phase by performing comparisons of the differences between Canadian GAAP and IFRS and is currently assessing the effects of adoption and finalizing its conversion plan. At this time, the impact on PET's financial position and results of operations is not reasonably determinable or estimable for any of the IFRS conversion impacts identified. The Trust will continue to monitor any changes in the adoption of IFRS and will update its plan as necessary.

2. CHANGE IN ACCOUNTING POLICY

On January 1, 2007, the PET adopted the new Canadian accounting standards for financial instruments. Prior periods have not been restated.

At January 1, 2007, the following adjustments were made to the balance sheet to adopt the new standards:

Changes to balance sheet accounts	At January 1, 2007
Financial instrument asset – current	$ 25,768
Financial instrument asset – long term	4,764
Other assets	(5,419)
Increase in assets	$ 25,113
Convertible debentures	$ 5,224
Deficit	(30,337)
Decrease in liabilities and reduction in deficit	$ (25,113)

a) Financial instruments

The Trust uses financial instruments and non-financial derivatives, such as fixed-price commodity sales contracts requiring physical delivery of the underlying commodity, to manage the price risk attributable to anticipated sale of petroleum and natural gas production.

The Trust accounts for its commodity sales contracts requiring physical delivery as non-financial derivatives. Prior to adoption of the new standards, physical receipt and delivery contracts did not fall within the scope of the definition of a financial instrument. Accordingly, the fair values of these financial instruments as at January 1, 2007 were recorded as an asset on the Trust's balance sheet with an offsetting credit to deficit. Changes in fair value of these financial instruments and changes in fair values of financial forward natural gas and foreign exchange contracts in each reporting period are recorded in earnings. Financial forward natural gas and foreign exchange contracts have been accounted for as derivatives since January 1, 2006 and as such the changes in the fair value of these contracts have been recorded to earnings since that time.

b) Convertible debenture issue costs

Costs related to the issuance of the Trust's convertible debentures (see note 8) are netted against the carrying value of the convertible debentures and amortized into earnings over the life of the convertible debentures using the effective interest rate method. Prior to January 1, 2007, transaction costs were recorded as deferred charges in other assets and recognized in net earnings on a straight-line basis over the life of the convertible debentures. On adoption, issue costs were adjusted to reflect the application of the effective interest rate method since the date of issue of the related convertible debentures.

c) Financial instruments

Effective January 1, 2008, the Trust adopted the accounting requirements for CICA Handbook Sections 3862 ''Financial Instruments – Disclosure'', 3863 ''Financial Instruments – Presentation'', and 1535 ''Capital Disclosures''. Disclosure and presentation requirements for financial instruments are intended to provide further information on the significance of financial instruments to the entity's financial position, performance and funds flows. The Trust has presented and disclosed the nature and extent of the risks arising from financial instruments and how the entity manages such risks. Capital disclosure requirements provide an overview of the Trust's objectives, policies and processes for managing its capital structure. Refer to disclosure in note 12 relating to each of the above standards.

A financial instrument is any contract that gives rise to a financial asset of one entity and a financial liability or equity instrument to another entity. Upon initial recognition all financial instruments, including derivatives, are recognized on the balance sheet at fair value. Subsequent measurement is then based on the financial instruments being classified into one of five categories: held for trading, held to maturity, loans and receivables, available for sale and financial liabilities measured at amortized cost. The Trust has designated its financial instruments into the following categories applying the indicated measurement methods:

Financial instrument	Category	Measurement method
Marketable securities	Held for trading	Fair value
Financial instrument assets and liabilities	Held for trading	Fair value
Accounts receivable	Loans and receivables	Amortized cost
Accounts payable and accrued liabilities	Financial liabilities	Amortized cost
Distributions payable	Financial liabilities	Amortized cost
Long term bank debt	Financial liabilities	Amortized cost
Convertible debentures	Financial liabilities	Amortized cost

Convertible debentures are classified as debt on the balance sheet with a portion of the debentures allocated to equity. The debt component has been measured based on amortized cost. The Trust will assess at each reporting period whether each financial asset, other than those classified as held for trading, is impaired. An impairment loss, if any, is included in net earnings.

The Trust has entered into certain financial derivative and fixed-price physical delivery sales contracts ("physical sales contracts") in order to reduce its exposure to market risks from fluctuations in commodity prices. These instruments are not used for trading or speculative purposes. The Trust has not designated its financial derivative or physical sales contracts as effective accounting hedges, even though the Trust considers all commodity contracts to be effective economic hedges. As a result, all financial derivative contracts and physical sales contracts are classified as held for trading and are recorded on the balance sheet at fair value, with changes in the fair value recognized as "unrealized gains and losses on financial instruments" on the Trust's statement of earnings. Settlements of financial derivative contracts are recognized in realized gains and losses on financial instruments and settlements of physical sales contracts are recognized in oil and natural gas revenue at the time each transaction under a contract is settled.

The Trust measures and recognizes embedded derivatives separately from the host contracts when the economic characteristics and risks of the embedded derivative are not closely related to those of the host contract, when it meets the definition of a derivative and when the entire contract is not measured at fair value. Embedded derivatives are recorded at fair value. The Trust continuously evaluates all new material contracts for existence of embedded derivatives. No material embedded derivatives have been identified throughout the course of these evaluations. Costs incurred to issue convertible debentures are recorded against the related financial liability. The Trust has not incurred any other material costs pertaining to the acquisition of financial assets or liabilities.

3. MARKETABLE SECURITIES

At December 31, 2008 marketable securities comprised of a $0.1 million investment in Ember Resources Inc. ("Ember"), a publicly traded oil and gas company. The Trust previously had an investment in Cordero Energy Inc. ("Cordero"). On July 4, 2008, Cordero entered into an agreement to sell all of its outstanding common shares to Ember in exchange for a combination of cash and common shares of the acquirer. The transaction between Cordero and Ember closed on September 5, 2008, at which time the Trust recorded proceeds on disposition of marketable securities of $0.8 million related to the cash component of the transaction. The decrease in market value of the remaining common share investment of $0.2 million for the twelve month period ended December 31, 2008 ($1.9 million decrease for the year ended December 31, 2007) has been included in interest and other expense on the statement of earnings.

4. PROPERTY, PLANT AND EQUIPMENT

	December 31, 2008	December 31, 2007
Petroleum and natural gas properties	**$ 2,051,890**	$ 1,971,066
Asset retirement costs	**154,720**	175,679
Corporate assets	**4,205**	2,617
	2,210,815	2,149,362
Accumulated depletion and depreciation	**(1,256,662)**	(1,052,024)
	$ 954,153	$ 1,097,338

Property, plant and equipment costs at December 31, 2008 included $126.8 million (December 31, 2007 - $142.9 million) currently not subject to depletion and $26.8 million (2007 - $30.4 million) of costs related to shut-in gas over bitumen reserves which are not being depleted due to the non-producing status of the wells in the affected properties.

Included in depletion, depreciation and accretion expense is a $4.4 million recovery resulting from a revision in the asset retirement obligation for the Trust's Saskatchewan cost centre (see note 11).

During the year the Trust had two non-core asset dispositions which resulted in the recording of a total of $6.0 million on gains of sale of property, plant and equipment.

In 2008 the Trust wrote off $9.5 million in expired leases and recorded a $12.0 million undeveloped land impairment, both recorded in exploration expense. In addition, the Trust recorded a write-down to property, plant and equipment in the amount of $2.7 million as a result of prescribed successful efforts impairment tests related to the Trust's properties. This write-down was recorded to depletion expense.

On December 3, 2007 PET closed the sale of the office building it formerly occupied in downtown Calgary for gross proceeds of $35.8 million. As a result, PET recorded a gain on sale of fixed assets of $22.0 million amounting to the difference between the carrying value and the purchase price of the building sold. In conjunction with this transaction, PET also repaid the related mortgage on the office building.

5. ACQUISITIONS

On June 26, 2007 PET closed the acquisition of a private oil and gas company and concurrent sale of certain net assets of the acquiree to a third party (the "Birchwavy Acquisition") for cash consideration of $391.8 million, plus $20.5 million in respect of working capital and acquisition costs of $3.8 million. The Birchwavy Acquisition was funded through the issuance of $250.5 million in subscription receipts which were converted into Trust Units upon closing of the acquisition (see note 9), $75.0 million in 6.5% convertible debentures (see note 8) and existing credit facilities. The acquisition was accounted for using the purchase method of accounting. The following table summarizes the fair value of the assets acquired and liabilities assumed at the date of acquisition.

Cash consideration	$ 391,800
Cash paid for net working capital	20,503
Acquisition costs	3,800
Cash consideration paid	$ 416,103
Property, plant and equipment	$ 450,640
Cash and cash equivalents	23,032
Accounts receivable	20,948
Other assets	2,026
Accounts payable and accrued liabilities	(24,702)
Asset retirement obligation	(55,841)
Cash consideration paid	$ 416,103

On April 30, 2007 the Trust closed the acquisition of producing petroleum and natural gas properties and assets in Northeast Alberta (the "Craigend/Radway/Stry Acquisition") for an aggregate purchase price of $45.2 million. The acquisition was financed through existing credit facilities.

6. NON-CONTROLLING INTEREST

PET has a 93 percent ownership interest in Severo Energy Corporation ("Severo"), a private company engaged in oil and gas exploration in Canada. The remaining seven percent is owned by employees of Severo and PET.

PET has nominated both representatives of the two person Board of Directors of Severo. Since the Trust has retained effective control of Severo, the results, assets and liabilities of this entity have been included in these financial statements. The non-PET ownership interests of Severo are shown as non-controlling interest.

7. BANK DEBT

At December 31, 2008 PET had a revolving credit facility with a syndicate of Canadian chartered banks (the "Credit Facility") with a borrowing base of $400 million consisting of a demand loan of $390 million and a working capital facility of $10 million. The revolving feature of the facility expires on May 25, 2009, if not extended. Upon expiry of the revolving feature of the facility, should it not be extended, amounts outstanding as of the expiry date will have a term to maturity date of one additional year. The Trust's lenders have completed their semi-annual borrowing base redetermination, resulting in a reconfirmation of the Trust's borrowing base at $400 million through April 30, 2009. In addition to amounts outstanding under the Credit Facility, PET has outstanding letters of credit in the amount of $4.4 million. Collateral for the Credit Facility is provided by a floating-charge debenture covering all existing and acquired property of the Trust, excluding the Severo assets, as well as unconditional full liability guarantees from all subsidiaries in respect of amounts borrowed under the Credit Facility. Should current borrowings exceed the borrowing base distributions would be restricted until such time that borrowings were once again below the borrowing base.

Advances under the Credit Facility are made in the form of Banker's Acceptances ("BA"), prime rate loans or letters of credit. In the case of BA advances, interest is a function of the BA rate plus a stamping fee based on the Trust's current ratio of debt to cash flow. In the case of prime rate loans, interest is charged at the lenders' prime rate. The effective interest rate on outstanding amounts at December 31, 2008 was 2.62 percent.

In addition, Severo has a 364 day extendible first senior revolving credit facility that was established on October 2, 2008 with a Canadian chartered bank in the amount of $10 million. At December 31, 2008 Severo had $9.8 million drawn on this facility.

8. CONVERTIBLE DEBENTURES

The Trust's 6.5% convertible unsecured subordinated debentures issued on June 20, 2007 ("6.5% Convertible Debentures") mature on June 30, 2012, bear interest at 6.5% per annum paid semi-annually on June 30 and December 31 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 6.5% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $14.20 per Trust Unit. During the year ended December 31, 2008, $0.1 million of 6.5% Convertible Debentures were converted, resulting in the issuance of 5,281 Trust Units.

The Trust's 6.25% convertible unsecured subordinated debentures issued on April 6, 2006 ("2006 6.25% Convertible Debentures") mature on April 30, 2011, bear interest at 6.25% per annum paid semi-annually on April 30 and October 31 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 2006 6.25% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $23.80 per Trust Unit.

The Trust's 6.25% convertible unsecured subordinated debentures issued on April 26, 2005 ("2005 6.25% Convertible Debentures") mature on June 30, 2010, bear interest at 6.25% per annum paid semi-annually on June 30 and December 31 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 2005 6.25% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $19.35 per Trust Unit.

The Trust's 8% convertible unsecured subordinated debentures ("8% Convertible Debentures") mature on September 30, 2009, bear interest at 8.0% per annum paid semi-annually on March 31 and September 30 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 8% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $14.20 per Trust Unit.

At the option of PET, the repayment of the principal amount of the convertible debentures may be settled in Trust Units. The number of Trust Units to be issued upon redemption by PET will be calculated by dividing the principal by 95 percent of the weighted average trading price for ten trading days prior to the date of redemption. The interest payable may also be settled with the issuance of sufficient Trust Units to satisfy the interest obligation.

	8% Series	2005 6.25% Series	2006 6.25% Series	6.5% Series	Total
Balance, December 31, 2006	$ 5,866	$ 55,038	$ 96,487	-	$ 157,391
June 20, 2007 issuance	-	-	-	75,000	75,000
Issue costs	-	-	-	(3,000)	(3,000)
Portion allocated to equity	-	-	-	(2,812)	(2,812)
Change in accounting policy (see note 2)	(112)	(1,436)	(3,676)	-	(5,224)
Accretion of non-cash equity component	-	116	731	291	1,138
Amortization of debenture issue fees	47	436	863	320	1,666
Converted into Trust Units	-	-	(24)	-	(24)
Balance, December 31, 2007	$ 5,801	$ 54,154	$ 94,381	$ 69,799	$ 224,135
Accretion of non-cash equity component	-	116	731	499	1,346
Amortization of debenture issue fees	47	443	865	601	1,956
Converted into Trust Units	-	-	-	(71)	(71)
Short term balance, December 31, 2008	**$ 5,848**	**-**	**-**	**-**	**$ 5,848**
Long term balance, December 31, 2008	**-**	**$ 54,713**	**$ 95,977**	**$ 70,828**	**$ 221,518**
Market value, December 31, 2008	**$ 5,749**	**$ 51,955**	**$ 69,970**	**$ 44,393**	**$ 172,067**
Principal amount of debentures outstanding, December 31, 2008	**5,866**	**55,271**	**99,972**	**74,925**	**236,034**

A reconciliation of the equity component of convertible debentures is provided below:

Balance, as at December 31, 2006	$ 4,527
Converted into Trust Units	(1)
Equity component of 6.5% Convertible Debentures	2,812
Balance, as at December 31, 2007	$ 7,338
Converted into Trust Units	(3)
Balance, as at December 31, 2008	**$ 7,335**

9. UNITHOLDERS' CAPITAL

a) Authorized

Authorized capital consists of an unlimited number of Trust Units and an unlimited number of Special Voting Units. No Special Voting Units have been issued to date.

b) Issued and Outstanding

The following is a summary of changes in Unitholders' capital:

Trust Units	Number of Units	Amount
Balance, December 31, 2006	85,186,011	$ 812,174
Units issued pursuant to Unit offering	20,450,000	250,513
Units issued pursuant to Unit Incentive Plan	244,500	1,665
Units issued pursuant to Bonus Rights Plan	981	12
Units issued pursuant to Distribution Reinvestment Plan	3,674,876	32,882
Units issued pursuant to conversion of debentures	1,050	25
Issue costs on convertible debentures converted to Trust Units	-	(1)
Trust Unit issue costs	-	(14,020)
Balance, December 31, 2007	109,557,418	1,083,250
Units issued pursuant to Unit Incentive Plan	75,000	662
Units issued pursuant to Bonus Rights Plan	65,491	914
Units issued pursuant to Distribution Reinvestment Plan	3,264,593	23,563
Units issued pursuant to conversion of debentures	5,281	75
Issue costs on convertible debentures converted to Trust Units	-	(2)
Trust Unit issue costs	-	(9)
Balance, December 31, 2008	**112,967,783**	**$ 1,108,453**

c) Per Unit information

Basic earnings per Trust Unit are calculated using the weighted average number of Trust Units outstanding (2008 - 111,472,580; 2007 – 98,106,775). PET uses the treasury stock method for incentive and bonus rights in instances where market price exceeds exercise price thereby impacting the diluted calculations. In computing diluted earnings (loss) per Trust Unit for the year ended December 31, 2008, 1,346,704 net Trust Units were added to the weighted average number of Trust Units outstanding (2007 – nil net Trust Units) for the dilutive effect of incentive rights and convertible debentures. In computing diluted earnings (loss) per Trust Unit 3,704,625 incentive rights were excluded as the exercise and conversion prices were out of the money at December 31, 2008 (2007 – 3,310,375 incentive rights). In addition, 12,746,394 potentially issuable Trust Units through Convertible Debentures (see note 8), were excluded as these instruments were anti-dilutive (2007 - 12,751,675 potentially issuable Trust Units through Convertible Debentures were excluded).

d) Redemption right

Unitholders may redeem their Trust Units at any time by delivering their Trust Unit certificates to the Trustee of PET. Unitholders have no rights with respect to the Trust Units tendered for redemption other than a right to receive the redemption amount. The redemption 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 ten day period after the Trust Units have been validly tendered for redemption and the “closing market price” of the Trust Units.

In the event that the aggregate redemption value of Trust Units tendered for redemption in a calendar month exceeds $100,000 and PET does not exercise its discretion to waive the $100,000 limit on monthly redemptions, PET will not use cash to pay the redemption amount for any of the Trust Units tendered for redemption in that month. Instead, PET 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 (“Notes”) to the tendering Unitholders.

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. The interest will be payable monthly. The Notes will be subordinated and, in certain circumstances, postponed to all of PET's indebtedness. Subject to prepayment, the Notes will be due and payable five years after issuance.

e) Distribution Reinvestment Plan (“DRIP”)

PET has a distribution reinvestment and optional Unit purchase plan (“DRIP plan”) which provides Unitholders with 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 price of the Trust Units for the ten trading days immediately proceeding a distribution payment date (“Treasury Purchase Price”). As well, subject to thresholds and restrictions described in the DRIP plan, it contains a provision for the purchase by Canadian unitholders of additional Trust Units with optional cash payments of up to $100,000 per participant per fiscal year of PET at the same six percent discount to the Treasury Purchase Price.

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 rein-vestment 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 cur-rently enrolled will instead receive cash distributions on the distribution payment dates. Should the Trust elect to rein-state 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.

10. INCENTIVE PLANS

a) Unit Incentive Plan

PET has adopted a Unit Incentive Plan ("Unit Incentive Plan") which permits the Administrator's Board of Directors to grant non-transferable rights to purchase Trust Units ("Incentive Rights") to its and affiliated entities' employees, officers, directors and other direct and indirect service providers. The purpose of the Unit Incentive Plan is to provide an effective long-term incentive to eligible participants and to reward them on the basis of PET's long-term performance and distributions. The Administrator's Board of Directors will administer the Unit Incentive Plan and determine participants, numbers of Incentive Rights and terms of vesting. The grant price of the Incentive Rights ("Grant Price") shall equal the per Trust Unit closing price on the trading date immediately preceding the date of the grant, unless otherwise permitted.

Prior to June 30, 2007, the exercise price of the Incentive Rights ("Exercise Price") was, subject to certain limitations, reduced by deducting from the Grant Price the aggregate amounts of all distributions on a per Trust Unit basis that PET pays its Unitholders after the date of grant which represented a return of more than 2.5 percent per quarter on PET's consolidated net property, plant and equipment on its balance sheet at each calendar quarter end ("Base Return"). The Exercise Price will be adjusted on a quarterly basis and in no case may it be reduced to less than $0.001 per Trust Unit. Effective June 30, 2007, the Base Return was reduced to nil in the formula for calculating Exercise Price reductions. The Incentive Rights are only dilutive to the calculation of earnings per Trust Unit if the exercise price is below the market price of the Trust Units. During the year ended December 31, 2008 the Trust recorded $4.8 million in Trust Unit compensation ($3.8 million for the year ended December 31, 2007) in respect of the Unit Incentive Plan.

At December 31, 2008 PET had 7.6 million Unit Incentive and Bonus Rights issued and outstanding relative to the 11.3 million (10 percent) of total Trust Units outstanding reserved under the Unit Incentive and the Bonus Rights Plans (see note 10 (b)). As at December 31, 2008, 1,861,500 Incentive Rights granted under the Unit Incentive Plan had vested but were unexercised (573,875 as of December 31, 2007).

PET used the binomial lattice option pricing model to calculate the estimated fair value of the outstanding Incentive Rights issued on or after January 1, 2003. The following assumptions were used to arrive at the estimate of fair value as at the date of grant:

		Year of grant
	2008	2007
Distribution yield (%)	**0.0**	0.0 – 6.3
Expected volatility (%)	**30.0 – 42.5**	28.5 – 29.5
Risk-free interest rate (%)	**1.65 – 3.46**	3.86 – 4.65
Expected life of Incentive Rights (years)	**3.75**	3.75 – 4.5
Vesting period of Incentive Rights (years)	**4.0**	4.0
Contractual life of Incentive Rights (years)	**5.0**	5.0
Weighted average fair value per Incentive Right on the grant date	**$ 2.18**	$ 1.82

Incentive Rights	Average exercise price	Incentive Rights
Balance, December 31, 2006	$ 14.60	3,644,675
Granted	6.97	3,661,875
Exercised	0.31	(244,500)
Forfeited	13.23	(371,175)
Balance, December 31, 2007	11.02	6,690,875
Granted	7.11	1,024,000
Exercised	4.42	(75,000)
Forfeited	7.91	(213,375)
Balance, December 31, 2008	**$ 10.64**	**7,426,500**

The following summarizes information about Incentive Rights outstanding at December 31, 2008:

Range of exercise prices	Number outstanding at December 31, 2008	Weighted average contractual life (years)	Weighted Average exercise price/ Incentive Right	Number exercisable at December 31, 2008	Weighted average exercise price/ Incentive Right
$4.38 - $6.83	3,594,875	3.5	$ 4.89	923,750	$ 4.70
$7.06 - $10.07	1,144,000	3.6	9.02	79,125	6.37
$10.41-$14.48	1,944,500	1.7	11.80	612,875	11.73
$14.55-$17.98	743,125	2.2	15.84	245,750	16.60
Total	7,426,500	2.8	$ 10.64	1,861,500	$ 8.66

b) Bonus Rights Plan

PET has implemented a bonus rights plan ("Bonus Rights Plan") for certain officers, employees and direct and indirect service providers of the Administrator ("Service Providers"). Rights to purchase Trust Units ("Bonus Rights") granted under the Bonus Rights Plan may be exercised during a period (the "Exercise Period") not exceeding three years from the date upon which the Bonus Rights were granted. The Bonus Rights vest over two years. At the expiration of the Exercise Period, any Bonus Rights which have not been exercised shall expire and become null and void. Upon vesting, the plan participant is entitled to receive the vested units plus an additional number of Trust Units equal to the value of distributions on PET's Trust Units as if the Trust Units were invested in PET's Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan") accrued since the grant date.

For the year ended December 31, 2008, $0.9 million in compensation expense was recorded in respect of the Bonus Rights granted (December 31, 2007 – $0.5 million).

The following table shows changes in the Bonus Rights outstanding under the Bonus Rights Plan:

	Bonus Rights
Balance, December 31, 2006	37,805
Granted	45,668
Exercised	(981)
Forfeited	(1,193)
Additional grants for accrued distributions	12,120
Balance, December 31, 2007	93,419
Granted	110,315
Exercised	(65,491)
Forfeited	(1,174)
Additional grants for accrued distributions	24,781
Balance, December 31, 2008	161,850

A reconciliation of contributed surplus is provided below:

Balance, as at December 31, 2006	$ 5,760
Trust Unit-based compensation expense	4,287
Transfer to Unitholders' capital on exercise of Incentive Rights	(1,590)
Transfer to Unitholders' capital on exercise of Bonus Rights	(11)
Balance, as at December 31, 2007	8,446
Trust Unit-based compensation expense	5,671
Transfer to Unitholders' capital on exercise of Incentive Rights	(330)
Transfer to Unitholders' capital on exercise of Bonus Rights	(914)
Balance, as at December 31, 2008	**$ 12,873**

11. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated based on PET's net ownership interest in all wells and facilities, estimated costs to reclaim and abandon these wells and facilities, excluding salvage values, and the estimated timing of the costs to be incurred in future periods. PET has estimated the net present value of its total asset retirement obligations to be $179.7 million as at December 31, 2008 based on an undiscounted total future liability of $363.2 million. These payments are expected to be made over the next 25 years with the majority of costs incurred between 2015 and 2020. PET used an average credit adjusted risk free rate of 8.0% to calculate the present value of the asset retirement obligation. During 2008 the Trust reduced its estimate of future well abandonment costs, resulting in a decrease in the asset retirement obligation of $21.9 million with a corresponding decrease to property, plant and equipment.

The following table reconciles the Trust's asset retirement obligations:

	December 31, 2008	December 31, 2007
Obligation, beginning of year	**$ 194,132**	$ 109,437
Obligations incurred	**3,523**	11,212
Obligations acquired	**-**	65,408
Obligations disposed	**(4,695)**	-
Revisions to estimates	**(21,915)**	-
Expenditures for obligations during the period	**(5,226)**	(2,597)
Accretion expense	**13,904**	10,672
	$ 179,723	$ 194,132

12. FINANCIAL RISK MANAGEMENT

The Trust has exposure to the following risks from its use of financial instruments:

- Credit risk
- Liquidity risk
- Market risk

This note presents information about the Trust's exposure to each of the above risks, the Trust's objectives, policies and processes for measuring and managing risk, and the Trust's management of capital. Further quantitative disclosures are included throughout these financial statements.

The Board of Directors has overall responsibility for the establishment and oversight of the Trust's risk management framework. The Board has implemented and monitors compliance with risk management policies.

The Trust's risk management policies are established to identify and analyze the risks faced by PET, to set appropriate risk limits and controls, and to monitor risks and adherence to market conditions and the Trust's activities.

a) Credit risk

Credit risk is the risk of financial loss to the Trust if a customer or counterparty to a financial instrument fails to meet its contractual obligations, and arises principally from the Trust's receivables from joint venture partners and petroleum and natural gas marketers.

Receivables from realized gains on financial gas sales arrangements are collected between the 2nd and 8th day of the month of the arrangement. The counterparties to these financial gas sales arrangements are large Canadian banks who have remained financially stable through the recent credit crisis. Receivables from petroleum and natural gas marketers are normally collected on the 25th day of the month following production. The Trust's policy to mitigate credit risk associated with these balances is to create marketing relationships with large, well established purchasers with high credit ratings. The Trust historically has not experienced any significant collection issues with its petroleum and natural gas marketing receivables. Joint venture receivables are typically collected within one to three months of the joint venture bill being issued to the partner. The Trust attempts to mitigate the risk from joint venture receivables by obtaining partner approval of significant capital expenditures prior to expenditure. However, the receivables are generally from participants in the oil and natural gas sector, and collection of the outstanding balances is dependent on the ability of the joint venture partner to pay, which is influenced by industry factors such as commodity price fluctuations, escalating costs, and the risk of unsuccessful drilling and oil and gas production. In addition, further risk exists with joint venture partners as disagreements occasionally arise that increase the potential for non-collection. The Trust does not typically obtain collateral from oil and natural gas marketers or joint venture partners; however, the Trust does have the ability in some cases to withhold production or amounts payable to joint venture partners in the event of non-payment.

The Trust manages the credit exposure related to marketable securities by monitoring the performance and financial strength of the investments and the liquidity of the securities being held.

During the period credit risk did not have any impact on the fair value of financial liabilities classified as held for trading.

The carrying amount of accounts receivable and marketable securities represents the maximum credit exposure. The Trust's allowance for doubtful accounts as at December 31, 2008 is $4.6 million; $4.0 million of the allowance pertains to the working capital component of the Birchwavy Assets acquired in 2007 and was included as part of the purchase price allocation (see note 5). The amount of the allowance was determined by assessing the probability of collection for each past due receivable related to the acquisition. The Trust is currently involved in negotiations with the joint venture partners involved in an effort to recover the receivables in question. The total amount of receivables past due 90 days amounted to $11.0 million as at December 31, 2008, and pertains primarily to Birchwavy assets. As at the balance sheet date, as a mitigating factor to the credit exposure, the Trust has $1.4 million payable to counterparties from which the Trust holds past due receivables.

b) Liquidity risk

Liquidity risk is the risk that the Trust will not be able to meet its financial obligations as they are due. The Trust's approach to managing liquidity is to ensure, as far as possible, that it will have sufficient liquidity to meet its liabilities when due, under both normal and stressed conditions without incurring unacceptable losses or risking harm to the Trust's reputation.

The Trust prepares annual capital expenditure budgets which are regularly monitored and updated as considered necessary. Further, the Trust utilizes authorizations for expenditures on both operated and non-operated projects to further manage capital expenditures. To facilitate the capital expenditure program, the Trust has a revolving credit facility as outlined in note 7. The lender reviews the Trust's borrowing base on a semi-annual basis. The following are the contractual maturities of financial liabilities and associated interest payments as at December 31, 2008:

Contractual repayments of financial liabilities	Total	2009	2010-2013	Thereafter
Accounts payable and accrued liabilities (1)	$ 61,770	$ 61,770	$ -	$ -
Bank debt – principal	$ 286,804	$ 9,828	$ 276,976	$ -
Convertible debentures – principal (2)	$ 236,034	$ 5,866	$ 230,168	$ -
Total	$ 584,608	$ 77,464	$ 507,144	$ -

(1) Current distribution payable is included in accounts payable and accrued liabilities.

(2) Assuming repayment of principal is not settled in Trust Units, at the option of PET.

Interest payments on financial liabilities	Total	2009	2010-2013	Thereafter
Interest payment on bank debt (1)	$ 10,531	$ 7,522	$ 3,009	$ -
Interest on convertible debentures (2)	$ 37,159	$ 14,925	$ 22,234	$ -
Total	$ 47,690	$ 22,447	$ 25,243	$ -

(1) Assuming revolving feature of the credit facility is not extended and calculated at the December 31, 2008 effective interest rate of 2.62%, assuming a constant debt level equivalent to the balance at December 31, 2008.

(2) Assuming payment of interest is not settled in Trust Units, at the option of PET.

c) Market Risk

Market risk is the risk that changes in market prices such as foreign exchange rates, commodity prices, and interest rates will affect the Trust's net earnings or the value of financial instruments. The objective of market risk management is to manage and control market risk exposures within acceptable limits, while maximizing returns.

The Trust utilizes both financial derivatives and physical delivery sales contracts to manage market risks related to commodity prices. All such transactions are conducted in accordance with the Trust's Risk Management Policy, which has been approved by the Board of Directors.

Foreign currency exchange rate risk

Foreign currency exchange rate risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in foreign exchange rates. The majority of the Trust's oil and natural gas sales are denominated in Canadian dollars. Due to the fact that the demand for oil and natural gas is substantially driven by the demand in the United States, the Trust's exposure to US dollar foreign exchange risk is indirectly driven by the price of oil and natural gas. From time to time the Trust also may use foreign exchange contracts to mitigate the effects of fluctuations in exchange rates on the Trust's cash flows. The Trust also enters into financial and physical natural gas sales contracts priced at AECO in Canadian dollars which effectively fixes the foreign currency exchange rate; refer to commodity price risk analysis below. As at December 31, 2008 the Trust had no outstanding forward foreign exchange rate contracts.

Commodity price risk

Commodity price risk is the risk that the fair value or future cash flows will fluctuate as a result of changes in commodity prices. Commodity prices for petroleum and natural gas are impacted by the world economic events that dictate the levels of supply and demand. The Trust has attempted to mitigate commodity price risk through the use of various financial derivative and physical delivery sales contracts. The Trust's policy is to enter into financial and forward physical gas sales contracts up to a maximum of 50 percent of forecasted production volumes including gas over bitumen deemed production, as outlined in the Trust's risk management policy.

As at December 31, 2008, the Trust has physical natural gas sales contracts which are contingent on future market prices. These contracts are not classified as financial instruments due to the fact that the settlement price corresponds directly with fluctuations in natural gas prices.

The remainder of production not subject to derivative contracts or fixed volume, non-derivative physical sales contracts is settled monthly with counterparties based on future monthly actual production and future monthly settlement prices.

For the period ended December 31, 2008 forward physical gas fixed-price sales contracts resulted in realized losses of $2.4 million that have been included in oil and natural gas revenue. In order to calculate these realized gains, PET compares the fixed price received to the AECO monthly index price and the NYMEX index.

The realized loss on financial instruments, including financial natural gas commodity contracts and foreign exchange price contracts, recognized in net earnings (loss) for year ended December 31, 2008 was $1.3 million (realized gains of $49.8 million for the year ended December 31, 2007).

Natural gas commodity contracts

At December 31, 2008 the Trust had entered into financial and forward physical gas sales arrangements at AECO as follows:

				Price ($/GJ)		
Type of contract	PET sold/bought	Volumes at AECO (GJ/d)	Fixed	Floor	Ceiling	Term
Financial	sold	2,500	$6.935	-	-	January 2009
Physical	sold	34,000	$6.211	-	-	January 2009
Physical	buy	(8,500)	$6.422	-	-	January 2009
Financial	sold	73,500	$7.743	-	-	January 2009 – March 2009
Financial	buy	(27,500)	$7.141	-	-	January 2009 – March 2009
Physical	sold	10,000	$8.223	-	-	January 2009 – March 2009
Physical	buy	(7,500)	$7.703	-	-	January 2009 – March 2009
Financial	sold	5,000	-	$7.000	$8.000	January 2009 – March 2009
Physical	sold	3,700	$6.466	-	-	February 2009
Physical	buy	(2,500)	$5.920	-	-	February 2009
Financial	sold	5,000	$6.245	-	-	February 2009 – March 2009
Financial	buy	(2,500)	$6.370	-	-	February 2009 – March 2009
Financial	sold	105,000	$7.776	-	-	April 2009 – October 2009
Financial	buy	(30,000)	$7.020	-	-	April 2009 – October 2009
Physical	sold	5,000	$8.645	-	-	April 2009 – October 2009
Physical	buy	(5,000)	$8.445	-	-	April 2009 – October 2009
Financial	sold	77,500	$8.529	-	-	November 2009 – March 2010
Financial	sold	72,500	$7.541	-	-	April 2010 – October 2010
Financial	sold	22,500	$8.361	-	-	November 2010 – March 2011

At December 31, 2008 the Trust had entered into financial call option gas sales arrangements, whereby the Trust's counterparty has the right to settle specified volumes of natural gas at specified prices in the future periods. In return for this option the counterparties have paid $3.4 million in upfront premiums as of December 31, 2008 (2007 – nil). These premiums have been included in unrealized gains on financial instruments in the Trust's statement of earnings (loss) as at December 31, 2008. Option premiums are reclassified to realized gains (losses) on financial instruments in the periods related to the option contracts. The above noted fair value of these call option contracts at December 31, 2008 has been included in unrealized gains on financial instruments and in financial instrument assets on the Trust's balance sheet.

Type of contract	PET sold/bought	Volumes at AECO (GJ/d)	Price ($/GJ) Fixed	Floor	Ceiling	Term
Financial	sold	5,000	-	-	$8.500	November 2009 – March 2010
Financial	sold	5,000	-	-	$7.750	April 2010 – October 2010
Financial	sold	12,500	-	-	$9.000	November 2010 – March 2011

At December 31, 2008 the Trust had entered into financial and forward physical gas sales arrangements at NYMEX as follows:

Type of contract	PET sold/bought	Volumes at NYMEX (MMBTU/d)	Price (US$/MMBTU)	Term
Financial	sold	72,500	$6.578	January 2009
Financial	buy	(72,500)	$6.535	January 2009
Financial	sold	2,500	$9.420	January 2009 – March 2009
Financial	buy	(2,500)	$9.260	January 2009 – March 2009

At December 31, 2008 the Trust had entered into financial and forward physical gas sales arrangements to fix the basis differential between the NYMEX and AECO trading hubs as follows. The price at which these contracts settle is equal to the NYMEX index less a fixed basis amount.

Type of contract	PET sold/bought	Volumes at NYMEX (MMBTU/d)	Price (US$/MMBTU)	Term
Financial – basis	sold	5,000	$ (0.750)	January 2009 – March 2009
Physical – basis	sold	5,000	$ (1.340)	January 2009 – March 2009
Physical – basis	buy	(5,000)	$ (1.435)	January 2009 – March 2009
Financial – basis	sold	12,500	$ (0.803)	April 2009 – October 2009
Financial – basis	buy	(2,500)	$ (0.930)	April 2009 – October 2009
Physical – basis	sold	10,000	$ (0.748)	April 2009 – October 2009
Financial – basis	sold	25,000	$ (0.684)	November 2009 – March 2010
Financial – basis	sold	5,000	$ 0.770)	April 2010 – October 2010
Physical – basis	sold	17,500	$ (0.445)	April 2010 – October 2010
Physical – basis	buy	(17,500)	$ (0.731)	April 2010 – October 2010
Financial – basis	sold	2,500	$ (0.680)	November 2010 – March 2011
Financial – basis	sold	15,000	$ (0.547)	April 2011 – October 2011
Financial – basis	buy	(15,000)	$ (0.550)	April 2011 – October 2011

At December 31, 2008 an unrealized gain of $38.7 million was recorded in the consolidated statement of earnings (loss) related to the change in fair value of financial and physical forward sales contracts from December 31, 2007 to December 31, 2008 (2007 – loss of $35.4 million).

The following table reconciles the Trust's unrealized gain/(loss) as stated on the statement of earnings (loss) and the statement of cash flows:

	December 31, 2008	December 31, 2007
Unrealized gain/(loss)	**$ 38,657**	$ (35,438)
Call option premiums received	**3,408**	-
Unrealized gain/(loss) as per statement of earnings	**$ 42,065**	$ (35,438)

The following table reconciles the Trust's financial instrument assets and liabilities as at December 31, 2008:

	Current Financial Instrument Asset (Liability)	Long Term Financial Instrument Asset (Liability)	Total
Balance at December 31, 2007	$ 18,447	$ 1,564	$ 20,011
Unrealized gain/(loss)	26,815	11,842	38,657
Balance at December 31, 2008	**$ 45,262**	**$ 13,406**	**$ 58,668**

Commodity price sensitivity analysis

As at December 31, 2008, if future natural gas prices changed by $0.25 per GJ for AECO contracts and $0.25 per MMBTU for NYMEX contracts, with all other variables held constant, net earnings for the year would have changed by $14.4 million. A potential increase in the natural gas price would result in a decrease to net earnings, while a decrease would lead to increased net earnings, as a result of the Trust's hedging program.

Mark to market sensitivity was based on published forward AECO and NYMEX prices. Gains and losses on NYMEX contracts were calculated based on the USD foreign exchange rate as at December 31, 2008.

Interest rate risk

The Trust utilizes a long-term debt credit facility which bears a floating rate of interest. Both of these financial liabilities are subject to interest rate risk. Increased future interest rates will decrease future cash flows and earnings, thereby potentially affecting the Trust's future distributions and capital investments.

PET's convertible debentures were issued at a fixed interest rate and as such the debentures are not materially impacted by market interest rate fluctuations. To ensure accounts payable, including monthly distributions, are settled on a timely basis, the Trust manages liquidity risk as previously outlined in this note, thus limiting exposure to interest rate fluctuations and other penalties potentially resulting from past due payables.

The Trust had no interest rate swap or financial contracts in place as at or during the three months ended December 31, 2008.

Interest rate sensitivity analysis

For year ended December 31, 2008, if interest rates had been 1 percent lower or higher, the impact on earnings would be as follows:

Interest rate sensitivity	1% increase	1% decrease
(Decrease)/Increase in net earnings	$ (3,300)	$ 3,300

The net earnings impact as a result of interest rate fluctuations is based on the assumption that the lender increases or decreases the fixed term BA rate consistently, based on a market interest rate change of 1 percent.

Capital management

The Trust's policy is to maintain a strong capital base so as to retain investor, creditor and market confidence and to sustain the future development of the business. The Trust manages its capital structure and makes adjustments in light of changes in economic conditions and the risk characteristics of the underlying oil and natural gas assets. The Trust considers its capital structure to include unitholders' capital, bank debt, convertible debentures and working capital. In order to maintain or adjust the capital structure, the Trust may from time to time issue units or debt securities and adjust its capital spending and distributions to manage current and projected debt levels. This overall objective and policy for managing capital remains unchanged in 2008 from prior reporting periods.

The Trust monitors capital based on the ratio of net debt to annualized funds flow, calculated as follows for the three months ended December 31, 2008:

Net debt	December 31, 2008
Long term bank debt	$ 276,976
Convertible debentures, measured at principal amount	236,034
Working capital deficiency (surplus) (2)	7,859
Net debt	520,869
Cash flow provided by operating activities	69,179
Exploration costs (3)	3,820
Expenditures on asset retirement obligations	1,636
Changes in non-cash operating working capital	(13,122)
Funds flow	61,513
Annualized funds flow (1)	$ 246,052
Net debt to annualized funds flow ratio (times) (1)	2.1

(1) These are non-GAAP measures; Management uses funds flow from operations before changes in non-cash working capital ("funds flow"), funds flow per Trust Unit and annualized funds flow to analyze operating performance and leverage. Funds flow as presented does not have any standardized meaning prescribed by Canadian Generally Accepted Accounting Principles ("GAAP") and therefore it may not be comparable to the calculation of similar measures for other entities. 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 provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP.

(2) Working capital deficiency (surplus) excludes short-term financial instrument assets and liabilities related to the Trust's hedging activities and the current portion of convertible debentures.

(3) Certain exploration costs are added back to funds flow in order to be more comparable to other energy trusts that use the full cost method of accounting for oil and gas activities. Exploration costs that are added back to funds flow include seismic expenditures, dry hole costs and expired leases and are considered by PET to be more closely related to investing activities than operating activities.

As at December 31, 2008, the Trust's ratio of net debt to annualized funds flow was 2.1 to 1. This ratio is monitored continuously by the Trust, and the targeted range of net debt to funds flow varies based on such factors as: acquisitions, commodity prices, forecasts of future commodity prices, price management contracts, projected cash flows, distributions, capital expenditure programs and timing of such programs. As a part of the management of this ratio, the Trust prepares annual capital expenditure budgets, which are updated as necessary depending on varying factors including current and forecast prices, successful capital deployment and general industry conditions. Capital spending budgets are approved by the Board of Directors.

The Trust's unitholders' capital, convertible debentures and working capital are not subject to external restrictions. The Trust's credit facility is subject to lender's covenants with which PET was in compliance with at December 31, 2008.

The capital structure at December 31, 2008 was as follows:

Net debt	$	520,869
Total equity (net of deficit) [(1)]		257,426
Non-controlling interest		1,871
Total capital at December 31, 2008	**$**	**780,166**

(1) As at December 31, 2008 the closing market price of Paramount Energy Trust's Units was $5.05.

Fair value of financial instruments

The Trust's financial instruments as at December 31, 2008 and December 31, 2007 include marketable securities, accounts receivable, derivative contracts, accounts payable and accrued liabilities, distributions payable, bank debt and convertible debentures.

The fair values of marketable securities and convertible debentures are based on exchanged traded values in active markets as at the balance sheet date.

The fair value of accounts receivable, accounts payable, accrued liabilities and distributions payable approximate their carrying amounts due to their short-terms to maturity.

The fair value of derivative contracts is based on the difference between the fixed contract price or fixed basis differential and readily observable estimated, external forward market price curves as at the balance sheet date, based on natural gas volumes in executed contracts.

Bank debt bears interest at a floating market rate and accordingly the fair market value approximates the carrying value.

13. COMMITMENTS

a) Operating leases

As of December 31, 2008, the future minimum payments under office lease costs and related sublease recoveries under contractual agreements consisted of:

Operating leases		
2009	$	2,956
2010		2,912
2011		728
Total commitment	$	6,596

b) Pipeline commitments

The Trust has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada. As of December 31, 2008, the future minimum payments under pipeline commitments under contractual agreements consisted of:

Pipeline commitments		
2009	$	7,108
2010		3,327
2011		2,141
2012		1,184
After 2013		2,310
Total commitment	$	16,070

14. FUTURE INCOME TAXES

The provision for income taxes in the financial statements differs from the result that would have been obtained by applying the combined federal and provincial tax rate to PET's earnings before income taxes. This difference results from the following items:

	2008	2007
Earnings (loss) before income taxes, including non-controlling interest	**$ 46,871**	$ (32,859)
Less non-taxable earnings (loss) of the Trust	**44,203**	(6,950)
Income (loss) for tax purposes	**2,668**	(25,909)
Combined federal and provincial tax rate (%)	**29.83**	32.40
Computed income tax expense (reduction)	**796**	(8,394)
Increase (decrease) in income taxes resulting from:		
Other	**(1,846)**	(1,924)
Initial recognition of temporary differences of the Trust	**-**	(19,307)
Valuation allowance	**(20,133)**	23,954
Change in tax rate	**37,269**	5,671
	$ 16,086	$ -

In 2007, new legislation was passed pursuant to which certain distributions will be subject to a trust-level tax and will be characterized as dividends to the Unitholders, commencing January 1, 2011. The federal government has also passed legislation reducing corporate tax rates, such that the combined federal and deemed Provincial tax rate for distributions is expected to be 29.5 percent in 2011 and 28 per cent in 2012. PET recorded future tax expense and a future tax liability of $16.1 million for 2008 (2007 – nil). Based on production forecasts for PET's reserves included in the independent reserve report as at December 31, 2008, the book values of the Trust's assets are projected to exceed the related tax values on January 1, 2011, the date the direct tax on distributions within the Trust becomes effective.

The components of the Trust's and its subsidiaries' future income tax liabilities at December 31 are as follows:

	2008	2007
Oil and natural gas properties	**$ 57,405**	$ 31,582
Asset retirement obligations	**(50,067)**	(53,934)
Non-capital losses	**(13,033)**	(19,463)
Valuation allowance	**50,886**	71,019
Capital losses	**(28,102)**	(28,201)
Other	**(1,003)**	(1,003)
	$ 16,086	$ -

The petroleum and natural gas properties and facilities owned by the Trust have an approximate tax basis of $695.6 million ($740.0 million in 2007) available for future use as deductions from taxable income. Included in this tax basis are estimated non-capital loss carry forwards of $93.3 million ($79.3 million in 2007) that expire in the years 2010 through 2027.

15. GAS OVER BITUMEN ROYALTY ADJUSTMENTS

On October 4, 2004 the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas which provide a mechanism whereby the Government may prescribe 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 Alberta Energy and Utilities Board (the "AEUB") as a result of recent bitumen conservation decisions. Such royalty reduction was initially prescribed in December 2004, retroactive to the date of shut-in of the gas production.

If production recommences from zones previously ordered to be shut-in, gas producers may pay an incremental royalty to the Crown on production from the reinstated pools, along with Alberta Gas Crown Royalties otherwise payable. The incremental royalty will apply only to the pool or pools reinstated to production and will be established at one percent after the first year of shut-in increasing at one percent per annum based on the period of time such zones remained shut-in to a maximum of ten percent. The incremental royalties payable to the Crown would be limited to amounts recovered by a gas well operator through the reduced royalty.

At December 31, 2008 PET had received $98.3 million ($77.6 million at December 31, 2007) for cumulative gas over bitumen royalty adjustments to that date. Of this amount, $23.7 million has been recorded as revenue to date and $74.6 million has been recorded on the Trust's balance sheet.

In 2008 PET disposed of certain shut-in gas wells in the gas over bitumen area for proceeds of $5.6 million, recording a $4.5 gain on sale of property, plant and equipment. As part of the disposition agreement the ownership of the natural gas reserves is transferred to the buyer and as such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer PET's responsibility, nor does the Trust retain the right to future gas over bitumen royalty adjustments. As a result of this disposition, the gas over bitumen royalty adjustments received to the date of the disposition by the Trust, for the affected wells, are now considered revenue since they will not be repaid to the Crown. As a result the Trust reclassified $2.1 million in previous gas over bitumen royalty adjustments from the balance sheet to the statement of earnings.

In 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. As a result of this disposition, the gas over bitumen royalty adjustments received by the Trust for the affected wells are now considered revenue since they will not be repaid to the Crown.

DIRECTORS

Clayton H. Riddell
Executive Chairman

Karen A. Genoway
Director (2) (3) (5)

Randall E. (Randy) Johnson
Director (1) (3) (5)

Robert A. Maitland
Director (1) (3) (5)

Donald J. Nelson
Director (2) (4)

John W. (Jack) Peltier
Director (1) (2) (4)

Howard R. Ward
Director (3) (4) (5)

(1) Member of Audit Committee
(2) Member of Reserves Committee
(3) Member of Corporate Governance
(4) Member of Environmental, Health & Safety Committee
(5) Member of Compensation Committee

OFFICERS

Susan L. Riddell Rose
President, Chief Executive Officer and Director (4)

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

Jeffrey R. Green
Vice President, Production Operations

Gary C. Jackson
Vice President, Land, Legal and Acquisitions

Kevin J. Marjoram
Vice President, Engineering Execution

Marcello M. Rapini
Vice President, Marketing

Roderick (Rick) P. Warters
Vice President, New Ventures and Geoscience

J. Christopher Strong
Acting Corporate Secretary, Corporate Counsel

TRUST INFORMATION

AUDITORS

KPMG LLP

BANKERS

Bank of Montreal

Canadian Imperial Bank of Commerce

The Bank of Nova Scotia

The Toronto-Dominion Bank

National Bank of Canada

ATB Financial

RESERVE EVALUATION CONSULTANTS

McDaniel & Associates Consultants Ltd.

TRUSTEE REGISTRAR AND TRANSFER AGENT

Computershare Trust Company of Canada

STOCK EXCHANGE LISTING

Toronto Stock Exchange

Trust Units PMT.UN

Convertible Debentures PMT.DB, PMT.DB.A, PMT.DB.B, PMT.DB.C

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Website: www.paramountenergy.com

ANNUAL MEETING

Unitholders are cordially invited to attend the
Annual General and Special Meeting
to be held June 18, 2009 at 3:00 p.m.

Calgary Petroleum Club
McMurray Room
319 5 Avenue SW
Calgary, Alberta

PARAMOUNT
ENERGY TRUST

3200, 605 – 5 Avenue SW
Calgary, Alberta CANADA
T2P 3H5

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STOCK EXCHANGE LISTING	**TSX**
TRUST UNITS	PMT.UN
CONVERTIBLE DEBENTURES	PMT.DB PMT.DB.A PMT.DB.B PMT.DB.C