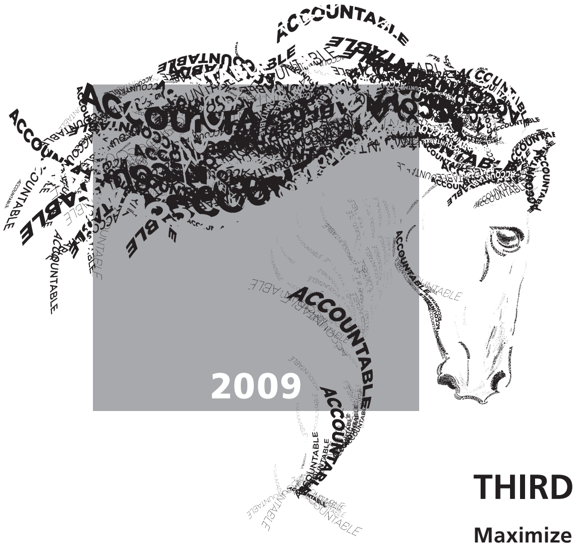

PARAMOUNT
ENERGY TRUST

CANADA'S PREMIUM NATURAL GAS TRUST

Paramount Energy Trust ("PET") is a high-yield income investment in the Canadian energy industry. Based in Calgary, Alberta, Canada 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 $13.614 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.

THIRD QUARTER SUMMARY

Maximize Cash Flow

- Average production measured 152.4 MMcfe/d for the third quarter of 2009 as compared to 183.7 MMcfe/d in the same period of 2008. With the significant downturn in natural gas prices, PET undertook a detailed analysis of the economic attributes of all of its properties and identified opportunities to preserve value through voluntary production curtailments. As a result of this analysis, the Trust shut in approximately 35 MMcfe/d of natural gas production in the second and early in the third quarter of 2009. As of November 1, 2009 approximately 20 MMcfe/d has been returned to production due to recent strengthening in natural gas prices.
- The Trust's realized gas price was $7.51 per Mcfe for Q3, a 14% decrease from the comparable quarter in 2008. The effect of the 67% decrease in AECO prices from quarter to quarter was largely offset by realized gains on financial instruments totaling $56.3 million, comprised of $14.9 million received for monthly settlements during the quarter and $41.4 million crystallized through the early termination of PET's AECO-based financial fixed price natural gas contracts for November 2009 through March 2010. The hedge price on the crystallized volumes was immediately reset to $5.38 per GJ to provide continued downside protection. PET collected $1.1 million in call option proceeds during the third quarter, further enhancing the Trust's realized gas price.
- Funds flow decreased to $59.6 million ($0.49 per Trust Unit) from $76.4 million ($0.68 per Trust Unit) for the third quarter of 2008 primarily due to lower gas prices and voluntary production shut-ins, partially offset by lower royalties and cost reductions in both the operating and administrative aspects of PET's operations. Funds flow netbacks for the quarter decreased 6% to $4.25 per Mcfe/d from $4.52 per Mcfe/d in the third quarter of 2008.
- Since the end of the third quarter, PET has locked in an additional $5.4 million in hedging gains relating to the reset natural gas hedging contracts put into place in late September for the November 2009 through March 2010 period.

Asset Optimization

- Exploration, development and land expenditures totaled $10.7 million in Q3 2009 and were focused on drilling and facilities in the Southern district. In addition, expenditures were made to evaluate the technical feasibility of developing a depleted gas reservoir for commercial gas storage in the Warwick area of east central Alberta.

Accretive Acquisitions

- On August 13, 2009, PET completed the second stage transaction to finalize the acquisition of Profound Energy Inc. This important strategic acquisition establishes a core operating position in the greater Pembina area in west central Alberta. These assets currently produce approximately 15 MMcfe/d, weighted 75% to natural gas. The transaction adds a significant number of higher impact, deep basin style resource play opportunities to PET's prospect inventory.
- PET has entered into a purchase and sale agreement to dispose of a non-core asset in northeast Alberta, producing approximately 2.1 MMcf/d, for net proceeds of $12 million. Closing is anticipated in November 2009.

Healthy Balance Sheet

- Net bank debt was reduced by $23.0 million during the quarter to $295.5 million from $318.5 million at June 30, 2009.
- On October 14, 2009, the Trust announced that it intends to seek debentureholder approval to combine and amend the terms of its 2005 6.25% and 2006 6.25% convertible debentures. The proposed changes to the terms include an increase of the coupon rate by 0.50% to 6.75%, a reduction of the conversion price to $8.40 per Trust Unit, an extension of the maturity date to October 31, 2016 and the provision of a four year non-call ending on October 31, 2013. The Trust has scheduled a meeting of debentureholders on November 13, 2009 to seek approval of the amendments.

Maximize Unitholder Value

- Distributions payable for the third quarter of 2009 totaled $0.15 per Trust Unit, comprised of $0.05 per Trust Unit paid on August 17, September 15 and October 15, representing a payout ratio of 30.7% of funds flow as compared to 44.0% for the third quarter of 2008.
- On September 21, 2009, PET announced that it had adopted a Premium Distribution™ component in its Distribution Reinvestment Plan (the "Premium DRIP Plan") payable with the September 2009 cash distribution and onwards. The Premium DRIP Plan supersedes, amends and restates in its entirety the Distribution Reinvestment and Optional Trust Unit Purchase Plan of PET dated December 17, 2003 (the "Original Plan"). The primary differences between the Premium DRIP Plan and the Original Plan are the addition of the Premium Distribution™ component, through which eligible Unitholders who enroll in the Premium DRIP Plan can elect to receive 102% of the regular monthly distribution, and the discontinuation of the Optional Trust Unit purchase component which was available under the Original Plan.

FINANCIAL AND OPERATING HIGHLIGHTS	Three Months Ended September 30			Nine Months Ended September 30		
($Cdn thousands except volume and per Trust Unit amounts)	**2009**	2008	% Change	**2009**	2008	% Change
Financial						
Revenue, including realized gains and losses on financial instruments	**105,274**	148,328	(29)	**339,741**	424,538	(20)
Funds flow (1)	**59,599**	76,380	(22)	**191,938**	213,921	(10)
Per Trust Unit (2)	**0.49**	0.68	(28)	**1.66**	1.93	(14)
Net earnings (loss)	**(44,151)**	180,796	(124)	**25,680**	39,771	(35)
Per Trust Unit (2)	**(0.36)**	1.62	(122)	**0.22**	0.36	(39)
Distributions	**18,324**	33,584	(45)	**57,028**	100,036	(43)
Per Trust Unit (3)	**0.15**	0.30	(50)	**0.49**	0.90	(46)
Payout ratio (%) (1)	**30.7**	44.0	(30)	**29.7**	46.8	(37)
Total assets	**1,099,869**	1,158,996	(5)	**1,099,869**	1,158,996	(5)
Net bank and other debt outstanding (4)	**295,549**	286,708	3	**295,549**	286,708	3
Convertible debentures, at principal amount	**230,168**	236,034	(2)	**230,168**	236,034	(2)
Total net debt (4)	**525,717**	522,742	1	**525,717**	522,742	1
Unitholders' equity	**268,611**	295,681	(9)	**268,611**	295,681	(9)
Capital expenditures						
Exploration and development	**10,666**	34,979	(70)	**58,092**	97,762	(41)
Acquisitions, net of dispositions	**18,723**	(9,733)	292	**114,376**	(16,371)	(798)
Other	**105**	235	(55)	**244**	661	(63)
Net capital expenditures	**29,494**	25,481	16	**172,712**	82,052	110
Trust Units outstanding (thousands)	**124,591**			**124,591**		
End of period	**123,955**	112,396	10	**123,955**	112,396	10
Weighted average	**121,452**	111,783	9	**115,861**	111,005	4
Incentive Rights outstanding	**7,201**	7,205	-	**7,201**	7,205	-
Trust Units outstanding at November 9, 2009	**124,591**			**124,591**		
Operating						
Production						
Total natural gas (Bcfe) (7)	**14.0**	16.9	(17)	**44.1**	50.6	(13)
Daily average natural gas (MMcfe/d) (7)	**152.4**	183.7	(17)	**161.6**	185.3	(13)
Gas over bitumen deemed production (MMcf/d) (5)	**17.5**	19.0	(8)	**18.1**	19.6	(8)
Average daily (actual and deemed - MMcfe/d) (5)	**169.9**	202.7	(16)	**179.7**	204.9	(12)
Per Trust Unit (cubic feet equivalent/d/Unit) (2)	**1.40**	1.81	(23)	**1.55**	1.85	(16)
Average natural gas prices ($/Mcfe)						
Before financial hedging and physical forward sales (6)	**3.41**	8.93	(62)	**4.26**	8.64	(51)
Including financial hedging and physical forward sales (6)	**7.51**	8.78	(14)	**7.69**	8.39	(8)
Land (thousands of net acres)						
Undeveloped land holdings	**2,009**	1,967	2	**2,009**	1,967	2
Drilling (wells drilled gross/net)						
Gas	**4/3.8**	25/20.5	(84)/(81)	**42/35.2**	67/51.8	(37)/(32)
Dry	**-/-**	-/-	-/-	**-/-**	2/1.6	(100)/(100)
Total	**4/3.8**	25/20.5	(84)/(81)	**42/35.2**	69/53.4	(39)/(34)
Success rate (%)	**100/100**	100/100		**100/100**	97/97	3/3

(1) These are Non-GAAP measures. Please refer to "Significant Accounting Policies and Non-GAAP Measures" included in management's discussion and analysis.

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

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

(4) Net debt includes net working capital (deficiency) before short-term financial instrument assets and liabilities and the current portion of convertible debentures. Total net debt includes convertible debentures measured at principal amount. Please refer to "Significant Accounting Policies and Non-GAAP Measures" included in management's discussion and analysis.

(5) The deemed production volume 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 its successor, the Energy Resources Conservation Board ("ERCB"), or through correspondence in relation to an AEUB ID 99-1 application. This deemed production volume is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution which is received monthly from the Alberta Crown as a reduction against other royalties payable.

(6) 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.

(7) Production amounts are based on the Trust's interest before royalties.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of PET's operating and financial results for the three and nine months ended September 30, 2009 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 interim consolidated financial statements and accompanying notes for the three and nine months ended September 30, 2009 and 2008 as well as the Trust's audited consolidated financial statements and accompanying notes and MD&A for the years ended December 31, 2008 and 2007. Readers are referred to the advisories regarding forecasts, assumptions and other forward-looking information contained in the "Forward Looking Information" section of this MD&A. The date of this MD&A is November 6, 2009.

Mcf equivalent ("Mcfe") may be misleading, particularly if used in isolation. In accordance with National Instrument 51-101 ("NI 51-101"), an Mcfe conversion ratio for oil of 1 bbl: 6 Mcf has been used, which is based on an energy equivalency conversion method primarily applicable at the burner tip and does not necessarily represent a value equivalency at the wellhead. For natural gas, gigajoules ("GJ") are converted to Mcf at a conversion ratio of 1.0546 GJ: 1 Mcf.

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 make reported funds flow in this MD&A 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 cash flow from operations before changes in non-cash working capital, settlement of asset retirement obligations 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 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	Three months ended September 30		Nine months ended September 30	
($ thousands except per Trust Unit amounts)	**2009**	2008	**2009**	2008
Cash flow provided by operating activities	**54,579**	72,556	**191,906**	190,585
Exploration costs (1)	**1,218**	918	**5,756**	5,358
Expenditures on asset retirement obligations	**483**	684	**2,913**	3,590
Changes in non-cash operating working capital	**3,319**	2,222	**(8,637)**	14,388
Funds flow	**59,599**	76,380	**191,938**	213,921
Funds flow per Trust Unit (2)	**$ 0.49**	$ 0.68	**$ 1.66**	$1.93

(1) 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 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.

OPERATIONS

Production

Natural gas production by core area (MMcfe/d)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Northern District				
Northeast (1)	**57.5**	67.7	**60.7**	66.3
Athabasca (1)	**38.9**	55.8	**44.2**	57.6
Northern District total	**96.4**	123.5	**104.9**	123.9
Southern District (1)				
Birchwavy West	**11.7**	23.2	**16.8**	23.0
Birchwavy East	**24.0**	28.3	**28.1**	29.6
Southern District total	**35.7**	51.5	**44.9**	52.6
West Central District	**14.5**	-	**4.9**	-
Severo Energy Corp.	**4.8**	6.9	**5.8**	7.0
Other	**1.0**	1.8	**1.1**	1.8
Total (2)	**152.4**	183.7	**161.6**	185.3
Deemed production from gas over bitumen financial solution	**17.5**	19.0	**18.1**	19.6
Total actual plus deemed production	**169.9**	202.7	**179.7**	204.9
Voluntary production shut-ins (2)	**35.0**	-	**14.4**	-

(1) In 2009 the Trust consolidated certain core areas in order to increase operating and general and administrative efficiencies. The Northeast core area combines the East Side and West Side areas, while the East Central district has been moved from the Southern district to the Northern district and included with Athabasca. Prior period production figures have been reclassified to conform to the current presentation.

(2) Third quarter production was reduced by approximately 35 MMcfe/d as a result of voluntary production shut-ins initiated in a number of producing areas in the Northern and Southern districts to preserve value during this period of low gas prices.

Average production measured 152.4 MMcfe/d for the three months ended September 30, 2009 as compared to 183.7 MMcfe/d reported in the third quarter of 2008. Actual plus deemed production totaled 169.9 MMcfe/d for the third quarter of 2009 as compared to 202.7 MMcfe/d in the prior period. With the significant downturn in natural gas prices, PET undertook a detailed analysis of the economic attributes of all of its properties in order to identify opportunities to preserve value through voluntary production curtailments. There is an expected gain in present value through the deferral of production until prices stabilize. Production deferral has the additional benefit of preserving reserves and the related lending value under the Trust's bank credit facility. Not all properties are suitable candidates for temporary shut-in due to operational considerations, fixed operating cost levels, and processing, joint venture and transportation arrangements. As a result of this analysis, the Trust shut in approximately 35 MMcfe/d of natural gas production in the second quarter and early in the third quarter. Including volumes attributed to the Profound Energy Inc. assets (see "Profound acquisition" in this MD&A), PET's current productive capacity is approximately 160 MMcfe/d. The Trust began to return some shut-in volumes to production in mid-October. As of November 1, 2009 approximately 20 MMcfe/d has been returned to production due to recent strengthening in natural gas prices.

Average production for the nine months ended September 30, 2009 decreased to 161.6 MMcfe/d from 185.3 MMcfe/d in the 2008 period due natural production declines and the voluntary production shut in discussed above, partially offset by the increase in production associated with the Profound acquisition.

Capital expenditures

Capital expenditures ($ thousands)	Three months ended September 30 2009	2008	Nine months ended September 30 2009	2008
Exploration and development expenditures (1)	**10,666**	34,979	**58,092**	97,762
Property acquisitions	**352**	2,020	**14,355**	2,374
Profound acquisition – cash consideration	**6,197**	-	**27,460**	-
Profound acquisition – Trust Unit consideration (2)	**13,414**	-	**32,008**	-
Profound acquisition – assumption of net debt	**-**	-	**51,246**	-
Dispositions	**(1,240)**	(11,753)	**(10,693)**	(18,745)
Other	**105**	235	**244**	661
Total capital expenditures	**29,494**	25,481	**172,712**	82,052

(1) Exploration and development expenditures for the three and nine months ended September 30, 2009 include approximately $1.2 million and $5.8 million, respectively in exploration costs (three and nine months ended September 30, 2008 - $1.0 million and $5.4 million, respectively) which have been expensed directly on the Trust's statement of earnings (loss) in accordance with the successful efforts method of accounting. Exploration costs including seismic expenditures and dry hole costs and are considered by PET to be more closely related to investing activities than operating activities, and therefore they are included with capital expenditures.

(2) Trust unit consideration for Profound for the nine months ended September 30, 2009 consisted of 10.0 million Trust Units (4.2 million Trust Units for the three months ended September 30, 2009) issued at a value of $3.21 per Trust Unit, using PET's weighted average unit trading price for the five trading days surrounding the acquisition announcement date.

Exploration, development and land expenditures totaled $10.7 million for the three months ended September 30, 2009, as compared to $35.0 million for the third quarter of 2008. The decrease is due to lower overall capital spending budget in 2009 as compared to the prior year. Capital expenditures for the third quarter of 2008 also included $16.9 million for the acquisition of several large parcels of exploratory acreage in west central Alberta. Capital spending in the current quarter was primarily directed towards drilling and facilities projects in the Southern district and PET's gas storage project in the Warwick area. Capital spending decreased from $97.8 million for the nine months ended September 30, 2008 to $58.1 million for the nine months ended September 30, 2009.

PET is in the final stages of evaluating the potential of a gas storage project located north of Vegreville, Alberta. The project targets a depleted gas reservoir proximal to the main Alberta gas transmission pipeline system and just south of the gas-consuming region of the Alberta oil sands. Based on PET's internal engineering estimates, the total cost of the project is projected to be $45 to $50 million including compression, cushion gas requirements, other facilities and the drilling of horizontal injection/withdrawal wells. PET expects to make its determination as to whether or not to move to full scale development of the project prior to the end of November 2009.

Subsequent to the end of the third quarter, PET entered into a purchase and sale agreement to dispose of a non-core asset in northeast Alberta, producing approximately 2.1 MMcf/d, for net proceeds of $12 million. Closing is anticipated in November 2009.

Profound acquisition

On August 13, 2009, PET completed the second stage of its acquisition of all the outstanding common shares of Profound Energy Inc. ("Profound"). The consideration, being 0.394 of a Trust Unit or $1.34 per Profound Share (subject to proration), valued the Profound acquisition at approximately $110.7 million including assumed debt and closing costs.

The Profound properties are located in a year-round access area within the Trust's new venture area in west central Alberta. The acquisition is another step in the strategic expansion of PET's asset base, complementing the Trust's existing shallow gas prospect inventory with a significant number of higher impact, deep basin style resource play opportunities. The Profound assets are currently producing approximately 15 MMcfe/d and are weighted 75 percent to natural gas.

MARKETING

Natural gas prices

	Three months ended September 30		Nine months ended September 30	
Natural gas prices ($/Mcfe, except percent amounts)	**2009**	2008	**2009**	2008
Reference prices				
AECO Monthly Index	**3.02**	9.25	**4.11**	8.58
AECO Daily Index	**3.00**	7.74	**3.79**	8.64
Alberta Gas Reference Price (1)	**2.92**	8.21	**3.78**	8.28
Average PET prices				
After financial hedging and physical forward sales	**7.51**	8.78	**7.69**	8.39
Percent of AECO Monthly Index (%)	**248**	95	**187**	98
Before financial hedging (3)	**3.41**	8.83	**4.29**	8.59
Percent of AECO Monthly Index (%)	**113**	96	**104**	100
Before financial hedging and physical forward sales (2)	**3.41**	8.93	**4.26**	8.64
Percent of AECO Monthly Index (%)	**113**	97	**104**	101

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

(2) 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 hedging and physical forward sales, 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.

Natural gas prices have experienced significant declines to date in 2009, as strong supply from shale gas plays in the United States and liquefied natural gas ("LNG") imports and weak industrial gas demand due to the economic recession in North America have contributed to very high gas storage levels compared to prior periods. PET's natural gas price before financial hedging and physical forward sales decreased by 62 percent for the three months ended September 30, 2009 to $3.41 per Mcfe from $8.93 per Mcfe in 2008 and by 51 percent for the first nine months of 2009 from the 2008 period, as compared to decreases in AECO Monthly Index prices of 67 percent and 52 percent for the respective periods. PET's natural gas price measured 113 percent of the AECO Monthly Index in the current quarter as compared to 97 percent of the AECO Monthly Index for the three months ended September 30, 2008 as a result of the increasing oil and natural gas liquids ("NGL") volumes included in the Trust's production portfolio.

The Trust's realized gas price was $7.51 for the third quarter of 2009, a 14 percent decrease from the comparable quarter in 2008. The effect of the 67 percent decrease in AECO prices was largely offset by realized gains on financial instruments totaling $56.3 million for the three months ended September 30, 2009, comprised of $14.9 million received for monthly settlements during the quarter and $41.4 million crystallized through the early termination of PET's AECO-based financial fixed price natural gas contracts for November 2009 through March 2010. In addition, PET collected $1.1 million in call option proceeds during the quarter, further enhancing the Trust's realized gas price.

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 Policy. 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.

The Trust recorded an unrealized loss on financial instruments of $45.8 million for the three months ended September 30, 2009. The loss is primarily due to the crystallization of $41.4 million gains on PET's hedging portfolio for November 2009 through March 2010, which has the effect of converting unrealized gains on financial instruments into realized gains. As these gains were being crystallized in September 2009 PET reset its hedging position on similar volumes for the same period at an average price of $5.38 per GJ. For a complete list of PET's outstanding financial instruments as at September 30, 2009, please see note 10 to the interim unaudited consolidated financial statements as at and for the three and nine months ended September 30, 2009.

PET may terminate in the money hedging instruments in advance of the stated maturity dates in order to lock in gains and cash flow to enhance the Trust's balance sheet and maintain distribution sustainability for Unitholders. To this end, since the end of the third quarter, PET has locked in an additional $5.4 million in hedging gains relating to the reset contracts put into place for the November 2009 through March 2010 period.

Financial and physical forward sales arrangements (net of related financial and physical fixed-price natural gas purchase contracts) at the AECO and NYMEX trading hubs as at November 6, 2009 are as follows:

Type of Contract	Volumes at AECO (GJ/d)	% of 2009 Forecast Production(2)	Price ($/GJ)(1)	Current Forward Price ($/GJ)	Term
Financial	145,000		3.99		October 2009(3)
Period Total	145,000	81	3.99	2.87	October 2009
Financial	75,000		5.38		November 2009(3)
Period Total	75,000	42	5.38	4.66	November 2009
Financial	25,000		5.38		December 2009
Period Total	25,000	14	5.38	4.80	December 2009
Financial	22,500		5.38		January – March 2010
Period Total	22,500	13	5.38	4.94	January – March 2010
Financial	107,500		7.24		April – October 2010
Period Total	107,500	60	7.24	4.87	April – October 2010
Physical	10,000		7.75		November 2010 – March 2011
Financial	107,500		7.78		November 2010 – March 2011
Period Total	117,500	65	7.77	5.99	November 2010 – March 2011
Financial	50,000		6.33		April – October 2011
Period Total	50,000	28	6.33	5.66	April – October 2011
Financial	89,679		6.78		January – March 2013
Period Total	89,679	50	6.78	6.78	January – March 2013

PET has also entered into financial collar arrangements as follows:

Type of Contract	Volumes at AECO (GJ/d)	% of 2009 Forecast Production	Price($/GJ) Floor	Price($/GJ) Ceiling	Current Forward Price ($/GJ)	Term
Financial	2,500	1	4.75	6.25	4.11	October – December 2009
Financial	1,000	1	5.00	7.55	4.53	October 2009 – March 2010

In addition to the positions shown in the preceding tables, the Trust also has fixed price financial sales contracts at the NYMEX trading hub for November 2009 for 5,000 MMBTU/d at an average price of US$4.31 per MMBTU.

As at November 6, 2009 the Trust had also 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	Volumes at NYMEX (MMBTU/d)	Price (US$/MMBTU)	Term
Financial	7,500	(0.69)	November 2009 – March 2010
Physical	30,000	(0.67)	November 2009 – March 2010
Period total	37,500	(0.68)	November 2009 – March 2010
Financial	7,500	(0.70)	December 2009 – March 2010
Period total	7,500	(0.70)	December 2009 – March 2010

As part of PET's risk management strategy, the Trust has also sold forward financial call options to counterparties to purchase natural gas from PET at strike prices in excess of current forward prices. Option premiums of $7.8 million have been received in respect of these transactions, of which $3.3 million was received in the second quarter of 2009, $1.1 million was received in the third quarter of 2009 and $3.4 million was included in 2008 funds flow. Call option contracts outstanding as of November 6, 2009 are as follows:

Type of Contract	Volumes at AECO (GJ/d)	% of 2009 Forecast Production(2)	Strike Price ($/GJ)(1)	Current Forward Price ($/GJ)	Term
Sold Call	5,000	3	8.50	4.86	November 2009 - March 2010
Sold Call	20,000	11	7.25	5.03	January – December 2010
Sold Call	5,000	3	7.75	4.87	April – October 2010
Sold Call	22,500	13	8.22	5.99	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.

(2) Calculated using 180,000 GJ/d and includes actual and gas over bitumen deemed projected production volumes and Profound production volumes from July 1, 2009.

(3) October and November financial contracts have already settled as of November 6, 2009, at AECO Monthly Index Prices of $2.87 and $4.66 respectively.

FINANCIAL RESULTS

Revenue

	Three months ended September 30		Nine months ended September 30	
Revenue ($ thousands)	**2009**	2008	**2009**	2008
Oil and natural gas revenue, before financial hedging (1)	**47,875**	149,216	**189,256**	434,486
Realized gains (losses) on financial instruments (2)	**56,335**	(888)	**145,884**	(9,948)
Call option premiums received (3)	**1,064**	-	**4,331**	-
Total revenue	**105,274**	148,328	**339,471**	424,538

(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 and options.

(3) Call option premiums received 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.

Total revenue decreased to $105.3 million for the three months ended September 30, 2009 compared to $148.3 million for the third quarter of 2008 primarily due to a 68 percent reduction in oil and natural gas revenue, which is the combined effect of a 62 percent drop in PET's average gas price before financial instruments and a 17 percent reduction in natural gas production, partially offset by a significant addition to revenues from the settlement of financial instruments related to the Trust's gas price management program. The Trust includes realized gains and losses on financial forward contracts in its calculation of realized natural gas prices after hedging. Despite a decrease of 67 percent in AECO natural gas prices from quarter to quarter, PET's realized gas price only decreased 14 percent, from $8.78 per Mcfe for the three months ended September 30, 2008 to $7.51 per Mcfe for the current period, as a result of PET's gas price management program and gains on early termination of financial instrument contracts.

For the nine months ended September 30, 2009, revenue decreased to $339.5 million from $424.5 million for the nine month comparative period in 2008 due to a 56 percent reduction in oil and natural gas revenue resulting from a 51 percent fall in PET's average natural gas price before financial instruments and a 13 percent reduction in production volumes related to voluntary production shut-ins, offset by significant gains on financial instruments.

Funds flow

Funds flow reconciliation	Three months ended September 30				Nine months ended September 30			
	2009		2008		2009		2008	
	$ millions	**$/Mcfe**	$ millions	$/Mcfe	**$ millions**	**$/Mcfe**	$ millions	$/Mcfe
Production (Bcfe)		**14.0**		16.9		**44.1**		50.6
Revenue (1)	**105.2**	**7.50**	148.3	8.78	**339.4**	**7.69**	424.5	8.39
Royalties	**(2.9)**	**(0.20)**	(27.1)	(1.61)	**(14.4)**	**(0.33)**	(74.2)	(1.47)
Operating costs	**(27.9)**	**(1.99)**	(32.8)	(1.94)	**(86.1)**	**(1.95)**	(94.3)	(1.87)
Transportation	**(2.3)**	**(0.16)**	(3.5)	(0.21)	**(8.9)**	**(0.20)**	(10.8)	(0.21)
Operating netback from production (3)	**72.1**	**5.15**	84.9	5.02	**230.0**	**5.21**	245.2	4.84
Gas over bitumen royalty adjustments	**1.8**	**0.13**	6.0	0.35	**7.1**	**0.16**	16.4	0.33
Lease rentals	**(1.1)**	**(0.08)**	(1.0)	(0.06)	**(2.9)**	**(0.07)**	(2.3)	(0.04)
General and administrative (2)	**(6.2)**	**(0.45)**	(6.4)	(0.38)	**(22.0)**	**(0.49)**	(22.7)	(0.45)
Interest and other (2)	**(3.2)**	**(0.23)**	(3.3)	(0.19)	**(8.9)**	**(0.20)**	(11.4)	(0.23)
Interest on convertible debentures (2)	**(3.8)**	**(0.27)**	(3.8)	(0.22)	**(11.4)**	**(0.26)**	(11.3)	(0.22)
Funds flow (2) (3)	**59.6**	**4.25**	76.4	4.52	**191.9**	**4.35**	213.9	4.23

(1) Revenue includes realized gains and 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

Royalty expense decreased from $27.1 million for the three months ended September 30, 2008 to $2.9 million for the current period as a result of a significant decrease in natural gas prices and lower natural gas production volumes. PET's average royalty rate (royalties as a percentage of revenues including gains and losses on financial instruments) decreased to 2.7 percent from 18.2 percent in the third quarter of 2008. The lower royalty rate in the current quarter is primarily due to the inclusion of $57.4 million in realized gains on financial instruments and call option premiums in PET's realized natural gas price, resulting in a realized price equivalent to 257 percent of the Alberta Gas Reference Price for the period. Alberta Crown royalties are based on the Alberta Gas Reference Price.

A portion of the decrease in the royalty rate in 2009 can also be attributed to the "New Royalty Framework" implemented by the Government of Alberta effective January 1, 2009. PET's assessment of the New Royalty Framework is that, based on the Trust's current profile of well productivity, Crown royalty rates before royalty credits for gas cost allowance and operating costs would be as shown below.

	AECO gas price ($/GJ)				
Estimated royalty rate	**$3.00**	**$4.00**	**$5.00**	**$6.00**	**$7.00**
Estimated Crown royalty rate in 2009	5.0%	5.0%	5.8%	10.3%	14.8%

PET's average royalty rate on natural gas revenues before financial instruments is 6.0 percent for the three months ended September 30, 2009, comprised of a 2.5 percent Crown royalty and 3.5 percent in freehold and overriding royalties paid to landowners. The Crown rate is below 5.0 percent due to credits received from the Alberta government for the Crown's share of natural gas processing and operating costs, which are recorded as reductions to Crown royalty expense.

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.

On June 25, 2009 the Government of Alberta announced that eligibility for the royalty incentives would be extended by one year through March of 2011.

Operating costs

Total operating costs decreased 15 percent to $27.9 million in the three months ended September 30, 2009 from $32.8 million for the same period in 2008. PET has initiated cost reduction initiatives at all operated fields to enhance competitiveness, profitability and efficiency in the current low gas price environment. Furthermore, voluntary production shut-ins in certain areas for economic reasons resulted in variable cost savings. Unit-of-production costs increased three percent from 2008 levels due to reduced production volumes, reflecting the substantial level of fixed costs inherent in PET's operations.

Transportation costs

Transportation costs decreased to $2.3 million for three month period ended September 30, 2009 as compared to $3.5 million for the three month period ended September 30, 2008 due to lower production volumes and a significant credit received from a joint venture partner in respect of prior year transportation expenses. Unit transportation costs were $0.16 per Mcfe for the three month period ended September 30, 2009 as compared to $0.21 per Mcfe in the third quarter of 2008. PET has reduced its transportation expenses by pursuing contracts to market gas directly to end users proximal to the Trust's northeast Alberta operations at market-based prices, which benefit from reduced transportation costs. Certain of these contracts were in place at PET's Legend property, which has been shut-in by the ERCB pursuant to Decision 2009-061(see "Gas over bitumen royalty adjustments" in this MD&A. The shut-in, coupled with increasing tolls for transportation of natural gas in Alberta will lead to higher unit transportation costs in future periods as compared to the current quarter.

Operating netback

PET's operating netback decreased $12.8 million to $72.1 million for the three months ended September 30, 2009 from $84.9 million for the three months ended September 30, 2008, due to reduced production volumes and lower natural gas prices, partially offset by significant reductions in royalty and operating expenses, as well as an increase in realized gains on hedging contracts.

Operating netback reconciliation ($ millions)	
Realized price decrease	(17.8)
Production decrease	(25.2)
Royalty decrease	24.2
Operating cost decrease	4.8
Transportation cost decrease	1.2
Decrease in operating netback	(12.8)

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, or its successor the Energy Resources Conservation Board ("ERCB") 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))

The Trust's net deemed production volume for purposes of the royalty adjustment was 17.5 MMcf/d in the third quarter of 2009. Deemed production represents all PET natural gas production shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the AEUB or ERCB, 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 1.5 MMcf/d from 19.0 MMcf/d for the three months ended September 30, 2008 as a result of the annual ten percent reduction in deemed production volumes discussed previously, partially offset by the acquisition of approximately 0.7 MMcf/d of deemed production in January 2009.

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 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.

For the three months ended September 30, 2009 the Trust received $1.9 million in gas over bitumen royalty adjustments, of which $0.3 million was classified as revenue and $1.6 million was recorded on the Trust's balance sheet, as compared to $6.0 million received in the third quarter of 2008. The decrease is attributed to lower Alberta Gas References Prices and an eight percent reduction in deemed production volumes from the three months ended September 30, 2008.

On October 16, 2009, the ERCB issued Decision 2009-061 in response to applications by Sunshine Oilsands Ltd. and Total E&P Canada Ltd. for the shut-in of gas in the Liege Field within the Athabasca Oil Sands Area. Having considered the evidence submitted to an interim hearing, the ERCB concluded that production of gas from 228 intervals in 158 wells may present a significant risk to future bitumen recovery, pending the outcome of the full hearing of the applications. The Board also decided to shut in gas on an interim basis from 51 additional intervals in the Liege Wabiskaw A Pool, 15 additional intervals in the Liege Leduc A Pool, two additional intervals in the Liege Wabiskaw O Pool, and one additional interval in the Liege Wabiskaw M Pool.

The ERCB ordered the interim shut-in of gas production effective October 31, 2009. Production from these intervals shall remain shut in pending the ERCB's final decision regarding Applications No. 1613543 and 1616123 (the "Applications"). Because this was an interim proceeding, the ERCB did not have the benefit of the entirety of the evidence and argument that will ultimately be made available, nor was the ERCB in a position to assess the merits based on the totality of evidence. Accordingly, the ERCB advised that the interim decision should not be considered as conclusive or permanent with regard to the issues to be addressed at the full hearing. The schedule put forth by the ERCB accommodates a full hearing on this matter to be held in the fourth quarter of 2010.

PET has 70 wells that are specifically named for interim shut-in. Production in respect of these wells in August 2009 was approximately 8.6 MMcf/d. An additional 18 wells with production in August 2009 of approximately 1.9 MMcf/d has been shut-in due to the shut-in of facilities in the area.

PET has applied for the royalty reductions provided in the Royalty Regulation for gas production shut in pursuant to this ERCB decision. At the current forward market for natural gas prices, and assuming the royalty reductions are applicable to all the wells impacted by Decision 2009-061, PET believes that the shut-in will not have a material impact on the future funds flow of the Trust.

General and administrative expenses

General and administrative expenses including non-cash items increased 25 percent to $9.5 million for the three months ended September 30, 2009 from $7.6 million for the three months ended September 30, 2008 as a result of higher non-cash stock-based compensation expense. The Trust recorded a $2.1 non-cash million charge for the current quarter related to the cancellation of 2.5 million Unit Incentive Rights. General and administrative expenses increased to $28.4 million for the nine months ended September 30, 2009 from $26.9 million in 2008, also due to higher stock-based compensation expense. Cash general and administrative expenses for the current three and nine month periods decreased by $0.2 million and $0.7 million, respectively from the comparable periods in 2008 due to the Trust's cost reduction initiatives, partially offset by additional expenses related to management of the Profound assets.

Interest expense

Interest and other expense totaled $3.2 million for the three months ended September 30, 2009 as compared to $3.9 million for the third quarter of 2008, due primarily to lower interest rates in the current quarter. Interest and other expense for the nine months ended September 30, 2009 decreased 23 percent or $2.6 million to $8.9 million from $11.5 million in 2008, due primarily to the decrease in interest rates and lower average bank debt balances to date in 2009.

Interest on convertible debentures for the three and nine months ended September 30, 2009 totaled $4.6 million and $13.8 million respectively, unchanged from $4.6 million and $13.8 million for the three and nine months ended September 30, 2008. Included in convertible debenture interest expense for the 2009 and 2008 quarters is $0.8 million of non-cash expenses related primarily to the amortization of debt issue costs ($2.4 million for the nine month periods in 2008 and 2009).

Funds flow

Funds flow netbacks decreased to $4.25 per Mcfe in the third quarter of 2009 from $4.52 per Mcfe in the comparable period for 2008, driven primarily by lower realized natural gas prices partially offset by a reduction in royalty expenses. Funds flow decreased to $59.6 million ($0.49 per Trust Unit) from $76.4 million ($0.68 per Trust Unit) for the third quarter of 2008 primarily due to lower gas prices and reduced production volumes, partially offset by lower royalties and cost reductions in both the operating and administrative aspects of PET's operations.

Exploration expense

Exploration costs include lease rentals paid on undeveloped lands, seismic expenditures, amortization expense on undeveloped lands 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 increased to $4.6 million for the three months ended September 30, 2009 from $2.0 million for the third quarter of 2008, due to higher amortization expense on undeveloped lands in the Northern district and geological and geophysical expenditures related to evaluation of the Trust's natural gas storage project.

Depletion, depreciation and accretion

Depletion, depreciation and accretion ("DD&A") expense decreased from $56.0 million in the third quarter of 2008 to $43.4 million in 2009 due primarily to lower production volumes and a nine percent reduction in PET's depletion rate to $3.09 per Mcfe, as compared to $3.32 per Mcfe in the third quarter of 2008. The decrease in the DD&A rate is due to improved finding and development costs for proved reserves experienced in 2008, as well as the DD&A rate on the Profound assets which were purchased at a lower cost per Mcfe of proved reserves relative to PET's other depletable assets.

Earnings (loss)

The Trust reported a net loss of $44.2 million ($0.36 per basic and diluted Trust Unit) for the three months ended September 30, 2009 as compared to net earnings of $180.8 million ($1.62 per basic and $1.60 per diluted Trust Unit) for the 2008 period. The net loss is due to an unrealized loss on financial instruments of $45.8 million caused by the early termination of financial instrument contracts and the change in the mark to market value of these contracts at the end of the quarter, and future tax expense of $6.1 million for the quarter. In the third quarter of 2008 PET recorded an unrealized gain on financial instruments of $168.9 million.

Asset retirement obligation

The Trust's asset retirement obligation is estimated by a third party consulting firm based on PET's net ownership interest in all wells and facilities and estimated costs to abandon wells, decommission facilities and reclaim leases and roads, discounted at a credit-adjusted interest rate to arrive at a net present value figure. The timing of asset retirement expenditures is estimated based on the reserve life of assets according to the Trust's external reserve report prepared as of December 31, 2008. These expenditures are currently expected to occur over the next 25 years with the majority of costs incurred between 2015 and 2020. PET's asset retirement obligation increased from $179.7 million at December 31, 2008 to $191.8 million at September 30, 2009 due to accretion expense and additional obligations relating to the Profound acquisition.

Income taxes

In 2007, legislation was passed (the "Trust Tax Legislation") pursuant to which certain distributions from publicly-traded specified investment flow through entities ("SIFTs"), including energy trusts, 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. PET has 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.

In 2008 the Department of Finance 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.

A variety of operational, tax and other factors need to be weighed in determining when and how PET will adjust its business and legal structure. PET is currently analyzing potential structures and courses of action and although the Trust has not yet made a final determination with respect to future changes in the structure of its business operations, it anticipates these changes to be in effect prior to December 31, 2010.

PET recorded future tax expense of $6.1 million for the three months ended September 30, 2009 (three months ended September 30, 2008 – nil), bringing the Trust's total future tax liability to $3.5 million, including the $13.8 million future tax asset recorded on the Profound acquisition. 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 item and does not affect the Trust's funds flows or its cash available for distributions.

Tax pools

Tax pool information ($ millions)	**As at September 30, 2009**
Canadian oil and gas property expense (COGPE)	**305**
Canadian development expense (CDE)	**138**
Canadian exploration expense (CEE)	**63**
Undepreciated capital cost (UCC)	**196**
Trust unit issue costs	**12**
Non-capital losses	**111**
Total	**825**

At September 30, 2009, the Trust's consolidated income tax pools are estimated to be $825 million. Tax pools increased significantly during the third quarter of 2009 as a result of the Profound acquisition. 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.

SUMMARY OF QUARTERLY RESULTS

Quarterly results				Three months ended
($ thousands except where noted)	**Sept 30, 2009**	June 30, 2009	Mar 31, 2009	Dec 31, 2008
Oil and natural gas revenues (1)	**47,875**	58,631	82,750	109,090
Natural gas production (MMcfe/d)	**152.4**	165.5	167.1	173.1
Funds flow (2)	**59,599**	91,186	41,154	61,513
Per Trust Unit - basic	**0.49**	0.81	0.36	0.55
Net earnings (loss)	**(44,151)**	(8,728)	78,559	(8,986)
Per Trust Unit - basic	**(0.36)**	(0.08)	0.70	(0.08)
- diluted	**(0.36)**	(0.08)	0.69	(0.08)
Realized natural gas price ($/Mcfe) (3)	**7.51**	9.10	6.46	7.61
Average AECO Monthly Index price ($/Mcf)	**3.02**	3.66	5.63	6.79

Quarterly results				Three months ended
($ thousands except where noted)	Sept 30, 2008	June 30, 2008	Mar 31, 2008	Dec 31, 2007
Oil and natural gas revenues (1)	149,216	166,199	121,878	109,919
Natural gas production (MMcfe/d)	183.7	188.4	183.8	190.3
Funds flow (2)	76,380	81,350	56,191	59,622
Per Trust Unit - basic	0.68	0.73	0.51	0.55
Net earnings (loss)	180,796	(55,365)	(85,660)	(4,970)
Per Trust Unit - basic	1.62	(0.50)	(0.78)	(0.05)
- diluted	1.60	(0.50)	(0.78)	(0.05)
Realized natural gas price ($/Mcfe) (3)	8.78	9.00	7.29	7.07
Average AECO Monthly Index price ($/Mcf)	9.25	9.35	7.13	6.00

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

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

(3) Realized natural gas price includes realized gains and losses on financial hedging and physical forward sales contracts.

Oil and natural gas revenues are a function of production levels and natural gas prices. 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 2009, when the AECO Monthly Index price averaged $3.02 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 quarters of 2008 and 2009 as a result of realized gas prices of $9.00 and $9.10 per Mcfe, respectively. Funds flows are lowest in the first quarter of 2009 due to lower realized gas prices coupled with the effects of declining production relative to previous quarters.

Net earnings were exceptionally high in the third quarter of 2008 and first quarter of 2009, as a result of unrealized gains on financial instruments of $168.9 million and $95.1 million, respectively. The net losses in the first and second quarters of 2008 and the third quarter of 2009 were due to unrealized losses of $79.2 million, $70.4 million and $45.8 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.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Capitalization and financial resources		Three months ended
($ thousands except per Trust Unit and percent amounts)	**September 30, 2009**	December 31, 2008
Long term bank debt	**291,017**	276,976
Working capital deficiency (surplus) (1)	**4,532**	7,859
Net bank debt (1)(2)	**295,549**	284,835
Convertible debentures, measured at principal amount	**230,168**	236,034
Net debt	**525,717**	520,869
Financial instrument assets, post-2009 settlement (3)	**(55,031)**	(13,406)
Net debt less post-2009 financial instrument assets (3)	**470,686**	507,463
Net bank debt less post-2009 financial instrument assets (3)	**240,518**	271,429
Trust Units outstanding (thousands)	**123,955**	112,968
Market price at end of period ($/Trust Unit)	**5.30**	5.05
Market value of Trust Units	**656,962**	570,488
Total capitalization (1)	**1,182,679**	1,091,357
Net debt as a percentage of total capitalization (%)	**44.5**	47.7
Annualized funds flow (1)	**238,396**	246,052
Net bank debt to annualized funds flow (times) (1)(2)	**1.2**	1.2
Net debt to annualized funds flow (times) (1)	**2.2**	2.1
Net bank debt less post-2009 financial instrument assets to annualized funds flow (times) (1)(2)(3)	**1.0**	1.1
Net debt less post-2009 financial instrument assets to annualized funds flow (times) (1)(3)	**2.0**	2.1

(1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in this MD&A. Annualized funds flow in the prior year column is for the fourth quarter of 2008.

(2) The Trust's convertible debentures are primarily long-term in nature, with $55.3 million due in 2010, $100.0 million due in 2011 and $74.9 million due in 2012. As such, the Trust considers both net bank debt and net debt as measures of leverage.

(3) The mark-to-market values of PET's financial instruments totaled $59.5 million at September 30, 2009 and $58.7 million at December 31, 2008. Financial instrument assets and liabilities are not included in the Trust's definition of working capital, but may be terminated by the Trust prior to the settlement dates in exchange for discounted cash payments from counterparties and used to reduce PET's outstanding bank debt. Post-2009 financial instruments have settlement dates ranging from January 2010 through October 2011 and can be settled without impacting funds flows from monthly hedging settlements in 2009.

PET has a revolving credit facility with a syndicate of Canadian chartered banks (the "Credit Facility"). The revolving nature of the facility expires on May 24th, 2010 if not extended. With the persistent weakness in natural gas prices in 2009, lenders have significantly reduced the natural gas price forecasts used in their credit evaluations. As a result PET expects that the borrowing base under the Credit Facility will be reduced by approximately ten percent in the next few weeks following the completion of the semi-annual borrowing base review by the lenders.

At current interest rates and applicable margins, the effective interest rate on the Trust's bank debt is approximately 3.8 percent. 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 in respect of amounts borrowed under the facility. Bank debt on PET's credit facility increased $14.0 million from December 31, 2008 due to the repayment of $52.4 million in Profound bank debt and $5.9 million in 8% convertible debentures, largely offset by strong funds flows resulting from the early termination of gas hedging contracts for a total of $89.1 million to date in 2009. In addition to amounts outstanding under the credit facility PET has outstanding letters of credit in the amount of $12.7 million.

At September 30, 2009 PET had three series of five-year convertible debentures outstanding for a total of $230.2 million, measured at principal amount. All series of debentures are repayable on the maturity date in cash or in Trust Units, at the option of PET. Additional information on convertible debentures is as follows.

Convertible debentures	2007 - 6.50%	2006 – 6.25%	2005 – 6.25%
Principal issued	75.0	100.0	100.0
Principal outstanding ($ millions)	74.9	100.0	55.3
Maturity date	June 30, 2012	April 30, 2011	June 30, 2010
Conversion price ($ per Trust Unit)	14.20	23.80	19.35
Fair market value ($ millions)	71.4	99.0	55.3

Fair values of debentures are calculated by multiplying the number of debentures outstanding at September 30, 2009 by the quoted market price per debenture at that date. None of the debentures were converted into Trust Units during the three or nine months ended September 30, 2009. The Trust's 2004 8% convertible unsecured subordinated debentures matured and were paid out in cash on September 30, 2009.

On October 14, 2009, the Trust announced that it intends to seek debenture holder approval to amend and extend the terms of the 2005 6.25% and 2006 6.25% Debentures. The proposed changes to the terms include an increase of the coupon rate by 0.50% to 6.75%, reduction of the conversion price to $8.40, extending the maturity date to October 31, 2016 and provision of a four year non-call ending on October 31, 2013. The Trust has scheduled a meeting of debenture holders on November 13, 2009 to seek approval of the amendments.

Net bank debt to annualized funds flow and net debt to annualized funds flow increased to 1.2 times and 2.2 times, respectively, for the quarter ended September 30, 2009 from 1.2 times and 2.1 times for the quarter ended December 31, 2008, respectively, as a result of a decrease in funds flows. The Trust has financial instrument assets totaling $59.5 million which are not included in net bank debt or net debt, but which may be terminated for cash in advance of the settlement dates in order to reduce debt levels. Net debt as a percentage of total capitalization decreased from 47.7 percent at December 31, 2008 to 44.4 percent at September 30, 2009 primarily resulting from an increase in outstanding PET trust units related to the Profound takeover transaction.

A reconciliation of the increase in net debt from December 31, 2008 to September 30, 2009 is as follows:

Reconciliation of net debt	($ millions)
Net debt, December 31, 2008	520.9
Capital expenditures (exploration & development and other)	58.3
Acquisitions, net of dispositions	3.7
Acquisition of Profound – cash consideration for shares	27.5
Assumption of Profound bank debt, net of working capital	51.2
Funds flow (1)	(191.9)
Distributions	57.0
Expenditures on asset retirement obligations	2.9
DRIP proceeds and cash received on exercise of unit incentive rights	(3.9)
Net debt, September 30, 2009	525.7

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

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:

- 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;
- Base production forecasts;
- Current financial and physical forward natural gas sales contracts;
- Forward market for natural gas prices;
- Site reclamation and abandonment expenditures; and
- Working capital requirements.

Distributions for the third quarter of 2009 totaled $18.3 million or $0.15 per Trust Unit consisting of $0.05 per Trust Unit paid on August 17, September 15 and October 15, 2009. The Trust's payout ratio, which is the ratio of distributions to funds flow, was 30.7 percent in the current quarter as compared to 44.0 percent for the third quarter of 2008. PET's distributions are less than funds flow as the Trust retains a portion of its funds flow to finance capital expenditures and debt repayments. 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 2009. From the inception of the Trust through to the September 2009 distribution paid on October 15, 2009, PET has paid over $1 billion in distributions to unitholders, or $13.614 per Trust Unit.

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

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

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

For the September distribution approximately 52.4 percent of the Trust's Unitholders participated in the Premium DRIP. In October, 57.6 percent of PET Unitholders were enrolled in the DRIP, including 31.3 percent in the Premium Distribution™ component of the Premium DRIP.

PET anticipates that distributions and capital expenditures for the remainder of 2009 will be funded by funds flow and proceeds from the DRIP plan; 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.

	Three months ended September 30		Nine months ended September 30	
Distributions ($ thousands)	**2009**	2008	**2009**	2008
Cash flow from operating activities	**54,579**	72,556	**191,906**	190,585
Net earnings (loss)	**(44,151)**	180,796	**25,680**	39,771
Distributions	**18,324**	33,584	**57,028**	100,036
Excess (shortfall) of cash flows from operating activities over distributions	**36,255**	38,972	**134,878**	90,549
Excess (shortfall) of net earnings (loss) over distributions	**(62,475)**	147,212	**(31,348)**	(60,265)

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 from 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 $36.3 million for the three months ended September 30, 2009 and $39.0 million for the three months ended September 30, 2008 compare to exploration and development expenditures on PET's cash flow statement of $9.4 million and $11.8 million for those periods, respectively. In periods where the excess of cash flows from operating activities over distributions is higher than exploration and development expenditures, the excess is applied to acquisitions or to reduce bank debt.

PET has elected to reduce distributions in 2009 in order to preserve balance sheet strength in an uncertain price environment.

The Trust has a shortfall of distributions over net earnings (loss) of $62.5 million and $31.3 million for the three and nine months ended September 30, 2009. Distributions typically vary substantially from net earnings due to the significant impact of non-cash items on earnings, such as unrealized gains and losses on financial instruments 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.

Outlook and sensitivities

PET has undertaken a number of measures to preserve its value and financial strength during this period of gas price instability, including:

- Enhanced gas price management initiatives;
- Operating and other cost reduction initiatives;
- A restricted capital spending program for the second half of 2009, focused on capital expenditures required for strategic or operational reasons;
- Selected voluntary temporary production shut-ins; and
- Reinstatement of the DRIP plan for the July 2009 distribution and until further notice, and supplementing the DRIP plan with the Premium DRIP plan.

The following table reflects PET's projected realized gas price, monthly funds flow and payout ratio at the current monthly distribution of $0.05 per Trust Unit for the fourth quarter of 2009 at certain AECO natural gas price levels, incorporating the Trust's current financial hedges and physical forward sales contracts, capital expenditures of $17 million and related production additions, closing of the non-core asset disposition for $12 million, operating costs of $23 million, cash general and administrative expenses of $12 million and an interest rate on bank debt of 4.3 percent. This information is intended to provide information to readers on estimated fourth quarter production, funds flows and debt levels and may not be appropriate for other purposes.

Funds flow outlook – Fourth quarter of 2009	Average AECO Monthly Index Gas Price ($/GJ) $3.00	$4.00	$5.00
Oil and natural gas production (MMcfe/d)	146	146	146
Realized gas price ($/Mcfe)	4.87	5.36	5.62
Funds flow ($millions) (1)	17	22	24
Per Trust Unit ($/Unit/month)	0.045	0.058	0.063
Payout ratio (%) (1)	111	86	79
Ending net bank debt ($millions) (1)	288	283	281
Ending net debt ($millions) (1)	518	513	511
Ending net bank debt to funds flow ratio (times) (2)	1.4	1.3	1.3
Ending net debt to funds flow ratio (times) (3)	2.5	2.4	2.4

(1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in management's discussion and analysis.

(2) Calculated as ending net bank debt divided by estimated annual funds flow.

(3) Calculated as ending net debt (including convertible debentures, whose maturity extends out to 2012) divided by estimated annual funds flow.

Funds flows for the second half of 2009 have to date been materially higher than projected in the Trust's outlook and sensitivities in the MD&A for the three and six months ended June 30, 2009, due primarily to the early termination of financial hedging agreements for proceeds of $41.4 million, which were included in funds flows for the current period.

The Board of Directors of the administrator of the Trust has approved an exploration and development capital expenditure budget of $81 million for 2010, including $22 million directed to west central Alberta. The program includes capital spending of $32 million in the first quarter, with the flexibility to adjust the remainder of the program upward or downward should gas prices improve or weaken as a result of gas storage levels after the winter heating season. The Trust intends to fund 2010 exploration and development expenditures from funds flow.

The following table reflects PET's projected realized gas price, monthly funds flow and payout ratio at the current monthly distribution of $0.05 per Trust Unit for 2010 at certain AECO natural gas price levels, incorporating the Trust's current financial hedges and physical forward sales contracts, capital expenditures of $81 million and related production additions, operating costs of $111 million, cash general and administrative costs of $33 million and an interest rate on bank debt of 4.5 percent. This information is intended to provide information to readers on estimated 2010 production, funds flows and debt levels and may not be appropriate for other purposes.

Funds flow outlook – 2010	Average AECO Monthly Index Gas Price ($/GJ) $4.00	$5.00	$6.00
Oil and natural gas production (MMcfe/d)	147	147	147
Realized gas price ($/Mcfe) (1)	6.68	7.05	7.43
Funds flow ($millions) (2)	175	187	195
Per Trust Unit ($/Unit/month)	0.112	0.120	0.125
Payout ratio (%) (2)	45	42	40
Ending net debt ($millions) (2)	470	458	450
Ending net debt to funds flow ratio (times) (4)	2.7	2.4	2.3

(1) PET's weighted average forward price on an average of 88,000 GJ/d for the period January 1 to December 31, 2010 is $7.24 per GJ.

(2) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in management's discussion and analysis.

(3) Calculated as ending net bank debt divided by estimated annual funds flow.

(4) Calculated as ending net debt (including convertible debentures, whose maturity extends out to 2012) divided by estimated annual funds flow.

PET's sensitivity to gas prices for both the remainder of 2009 and 2010 has changed with changes in its financial and forward physical hedging position, including the early crystallization of hedging gains in the current period. Sensitivity of PET's fund flows to changes in production volumes, operating and general and administrative costs and interest rates has not varied significantly from the sensitivity analysis presented in the Trust's management's discussion and analysis for the year ended December 31, 2008.

OTHER SIGNIFICANT ACCOUNTING POLICIES AND NON-GAAP MEASURES

Payout ratio

Payout ratio refers to distributions 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 Mcfe of oil and 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 funds flow from operations, net earnings per Trust Unit or other measures of financial performance calculated in accordance with GAAP.

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 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.

Revenue, including realized gains (losses) on financial instruments

Revenue, including realized gains (losses) on financial instruments, includes call option premiums received and 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 and net bank debt

Net bank 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. Net debt includes convertible debentures, measured at principal amount. Net bank debt and net debt are used by management to analyze leverage. Net bank debt and 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.

Working capital (deficiency)

Working capital and working capital deficiency are calculated by the Trust as current assets less current liabilities, excluding assets and liabilities relating to financial instruments and the current portion of convertible debentures, in order to analyze short-term cash requirements without including mark-to-market balances that may settle for significantly different amounts than those presented on the balance sheet. Working capital (deficiency) as presented does not have any standardized meaning prescribed by GAAP and therefore it may not be comparable with the calculation of working capital (deficiency) for other entities.

INTERNAL CONTROLS

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 Canadian Generally Accepted Accounting Principles ("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.

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. PET's Chief Executive Officer and Chief Financial Officer have concluded, based on their evaluation as of September 30, 2009 that the Trust's disclosure controls and procedures are effective to provide reasonable assurance that material information related to PET, including its consolidated subsidiaries, is made known to them by others within those entities. During the three months ended September 30, 2009, there have been no changes in PET's internal control over financial reporting that have materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

NEW ACCOUNTING STANDARDS

Effective January 1, 2009, the Trust adopted Canadian Institute of Chartered Accountants ("CICA") Handbook Section 3064 "Goodwill and Intangible Assets", which replaced Section 3062 "Goodwill and Other Intangible Assets". The new standard gives guidance on the recognition of intangible assets as well as the recognition and measurement of internally developed intangible assets. Adopting this new standard did not have a material effect on PET's financial statements.

In May 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures," to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements.

Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust for the year ended December 31, 2009, and should not have a significant impact on the Trust's financial statements.

The CICA has also released new accounting standards for implementation effective January 1, 2011, as follows:

a) Section 1582 – Business Combinations. The new standard replaces the previous business combinations standard and requires assets and liabilities acquired in a business combination, contingent consideration and certain acquired contingencies to be measured at their fair values as of the date of acquisition. Transaction costs will be charged to earnings as opposed to being included in the cost of the acquisition.

b) Section 1601 – Consolidated Financial Statements and Section 1602 – Non-Controlling Interests. The new standards provide revised requirements for preparing consolidated financial statements. Section 1602 requires a non-controlling interest in a subsidiary to be classified as a separate component of equity, and requires that net earnings (losses) be attributed to both the parent and the non-controlling interest.

Although early adoption of both of these new standards is permitted, the Trust has elected not to early-adopt these standards with respect to the Profound transaction.

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. PET staff was involved in external IFRS training and development by means of attending conferences, participating in special interest seminars, and focusing on numerous external training sessions. 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. PET, as a successful efforts reporter under Canadian GAAP, anticipates that IFRS transition adjustments on its oil and gas interests will not be as extensive had it been full cost oil and gas reporter. 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.

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.

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.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

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.

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, provided they comply with the normal growth provisions as prescribed by the Trust Tax Legislation, will be subject to the new tax in January 2011. Once applied the new tax will affect PET's funds flow and may impact cash distributions from the Trust.

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

Gas over bitumen issue

On July 24, 2007 the ERCB's predecessor, the Alberta Energy and Utilities Board ("AEUB") released Decision 2007-056 related to the application for shut-in of certain natural gas production in northeast Alberta. Although PET does not produce natural gas 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. It is possible that such a strategy, when drafted and implemented by the AEUB, 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.

On July 22, 2009 PET received notice that the ERCB will conduct written hearings of Applications Nos. 1613543 and 1616123 (the "Applications") from oil sands operators for the potential interim shut in of gas production from the Liege Wabiskaw O Pool of the Athabasca Oil Sands Area of northeast Alberta. The subject applications could result in the shut in of approximately 8.8 MMcf/d of the Trust's natural gas production in the Legend area.

On October 16, 2009 PET announced that the ERCB issued Decision 2009-061 in response to applications by Sunshine Oilsands Ltd. and Total E&P Canada Ltd. for the shutin of gas in the Liege Field within the Athabasca Oil Sands Area. Having considered the evidence submitted to an interim hearing, the ERCB concluded that production of gas from 228 intervals in 158 wells may present a significant risk to future bitumen recovery, pending the outcome of the full hearing of the applications. The Board also decided to shut in gas on an interim basis from 51 additional intervals in the Liege Wabiskaw A Pool, 15 additional intervals in the Liege Leduc A Pool, two additional intervals in the Liege Wabiskaw O Pool, and one additional interval in the Liege Wabiskaw M Pool. The ERCB ordered the interim shut-in of gas production effective October 31, 2009.

PET has 70 wells that are specifically named for interim shut-in. Production in respect of these wells in August 2009 was approximately 8.6 MMcf/d. An additional 18 wells with production in August 2009 of approximately 1.9 MMcf/d have been shut-in due to the shut-in of facilities in the area.

Depletion of reserves

The Trust has certain unique attributes which differentiate it from some 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 some 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 $125 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.

Other risks and uncertainties affecting PET's operations are substantially unchanged from those presented in the MD&A for the year ended December 31, 2008.

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;
- expectations regarding the ability of the Trust to fund capital programs through funds flow;
- 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;
- potential natural gas production shut-ins related to ERCB gas over bitumen rulings and the applicability of Crown royalty reductions to such production;
- 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 is not exhaustive. The forward-looking statements contained in this MD&A are made as at the date of this MD&A and PET does not undertake any obligation to update publicly or to revise any of the forward-looking statements, whether as a result of new information, future events or otherwise, except as may be required by applicable securities laws.

Additional information on PET, including the most recent filed annual report and annual information form, can be accessed from SEDAR at www.sedar.com or from the Trust's website at www.paramountenergy.com.

CONSOLIDATED BALANCE SHEETS

As at	September 30, 2009	December 31, 2008
($ thousands, unaudited)		
Assets		
Current assets		
Accounts receivable	**$ 34,087**	$ 63,612
Marketable securities	**175**	127
Financial instruments (note 10)	**34,037**	45,262
	68,299	109,001
Property, plant and equipment (note 2)	**977,021**	954,153
Goodwill	**29,129**	29,129
Financial instruments (note 10)	**25,420**	13,406
	$ 1,099,869	$ 1,105,689
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 24,834**	$ 50,473
Distributions payable	**6,197**	11,297
Bank debt (note 5)	**7,763**	9,828
Convertible debentures (note 6)	**55,131**	5,848
	93,925	77,446
Long term bank debt (note 5)	**291,017**	276,976
Gas over bitumen royalty adjustments (notes 12 and 13)	**80,610**	74,643
Asset retirement obligations (note 9)	**191,808**	179,723
Convertible debentures (note 6)	**168,821**	221,518
Future income taxes	**3,494**	16,086
Non-controlling interest (note 4)	**1,583**	1,871
Unitholders' equity		
Unitholders' capital (note 7)	**1,145,489**	1,108,453
Equity component of convertible debentures (note 6)	**7,335**	7,335
Contributed surplus (note 8)	**18,370**	12,873
Deficit	**(902,583)**	(871,235)
	268,611	257,426
	$ 1,099,869	$ 1,105,689

See accompanying notes

Basis of presentation: note 1

Commitments and contingency: notes 10, 11, 12 and 13

INTERIM CONSOLIDATED STATEMENTS OF EARNINGS (LOSS) AND DEFICIT

	Three months Ended September 30		Nine months Ended September 30	
	2009	2008	**2009**	2008
($ thousands except per unit amounts, unaudited)				
Revenue				
Natural gas	**$ 47,875**	$ 149,216	**$ 189,256**	$ 434,486
Royalties	**(2,869)**	(27,147)	**(14,386)**	(74,177)
Realized gain on financial instruments (note 10)	**56,335**	(888)	**145,884**	(9,948)
Unrealized gain (loss) on financial instruments (note 10)	**(45,761)**	168,878	**(25)**	19,243
Call option premiums received (note 10)	**1,064**	-	**4,331**	-
Gas over bitumen revenue (note 12)	**263**	1,016	**1,109**	2,896
	56,907	291,075	**326,169**	372,500
Expenses				
Operating	**27,937**	32,753	**86,122**	94,346
Transportation costs	**2,304**	3,493	**8,913**	10,818
Exploration expenses	**4,559**	2,017	**15,243**	7,675
General and administrative (note 8)	**9,484**	7,596	**28,374**	26,929
Interest and other	**3,181**	3,876	**8,874**	11,460
Interest on convertible debentures	**4,623**	4,619	**13,804**	13,786
Gain on sale of property, plant and equipment	**-**	-	**(197)**	(1,528)
Depletion, depreciation and accretion	**43,380**	56,018	**138,871**	169,413
	95,468	110,372	**300,004**	332,899
Earnings (loss) before income taxes	**(38,561)**	180,703	**26,165**	39,601
Future income tax expense	**6,118**	-	**1,220**	-
Current taxes	**-**	-	**-**	-
	6,118	-	**1,220**	-
Net earnings (loss) before non-controlling interest	**(44,679)**	180,703	**24,945**	39,601
Non-controlling interest (note 4)	**528**	93	**735**	170
Net earnings (loss)	**(44,151)**	180,796	**25,680**	39,771
Deficit, beginning of period	**(840,108)**	(975,576)	**(871,235)**	(768,099)
Distributions declared	**(18,324)**	(33,584)	**(57,028)**	(100,036)
Deficit, end of period	**(902,583)**	(828,364)	**(902,583)**	(828,364)
Accumulated other comprehensive income	**-**	-	**-**	-
Deficit and accumulated other comprehensive income, end of period	**$ (902,583)**	$ (828,364)	**$ (902,583)**	$ (828,364)
Earnings (loss) per Trust Unit (note 7(c))				
Basic	**$ (0.36)**	$ 1.62	**$ 0.22**	$ 0.36
Diluted	**$ (0.36)**	$ 1.60	**$ 0.22**	$ 0.35
Distributions per Trust Unit	**$ 0.15**	$ 0.30	**$ 0.49**	$ 0.90

See accompanying notes

INTERIM CONSOLIDATED STATEMENTS OF CASH FLOWS

	Three months ended September 30		Nine months ended September 30	
	2009	2008	**2009**	2008
($ thousands, unaudited)				
Cash provided by (used for)				
Operating activities				
Net earnings (loss)	**$ (44,151)**	$ 180,796	**25,680**	$ 39,771
Items not involving cash				
Depletion, depreciation and accretion	**43,380**	56,018	**138,871**	169,413
Trust Unit-based compensation	**3,238**	1,167	**6,345**	4,195
Unrealized loss (gain) on financial instruments	**45,761**	(168,878)	**25**	(19,243)
Gain on sale of property, plant and equipment	**-**	-	**(197)**	(1,528)
(Gain) or loss on marketable securities	**(34)**	571	**(48)**	27
Future income tax expense	**6,118**	-	**1,220**	-
Non-cash interest expense on convertible debentures	**813**	828	**2,452**	2,474
Non-cash exploration expense	**2,209**	65	**6,601**	65
Non-controlling interest	**(528)**	(93)	**(735)**	(170)
Gas over bitumen royalty adjustments	**1,575**	4,988	**5,968**	13,559
Expenditures on asset retirement obligations	**(483)**	(684)	**(2,913)**	(3,590)
Change in non-cash working capital	**(3,319)**	(2,222)	**8,637**	(14,388)
Cash flow provided by operating activities	**$ 54,579**	$ 72,556	**$ 191,906**	$ 190,585
Financing activities				
Issue of Trust Units	**628**	-	**1,178**	3,832
Distributions to Unitholders	**(15,323)**	(25,535)	**(54,027)**	(83,121)
Repayment of convertible debentures	**(5,866)**	-	**(5,866)**	-
Change in bank debt	**(26,609)**	(27,683)	**(40,473)**	(48,116)
Change in non-cash working capital	**3,580**	3,170	**(2,716)**	2,375
	(43,590)	(50,048)	**(101,904)**	(125,030)
	$ 10,989	$ 22,508	**$ 90,002**	$ 65,555
Investing activities				
Acquisition of properties and corporate assets	**(457)**	(2,255)	**(14,599)**	(3,035)
Acquisition of Profound (note 3)	**(6,197)**	-	**(27,460)**	-
Acquisition of non-controlling interest (note 3)	**447**	-	**447**	-
Exploration and development expenditures	**(9,448)**	(34,061)	**(52,308)**	(92,404)
Proceeds on sale of property and equipment	**1,240**	11,753	**10,693**	18,745
Proceeds on sale of marketable securities	**-**	770	**-**	770
Change in non-cash working capital	**3,426**	1,285	**(6,775)**	10,369
	$ (10,989)	$ (22,508)	**$ (90,002)**	$ (65,555)
Change in cash	**-**	-	**-**	-
Cash, beginning of period	**-**	-	**-**	-
Cash, end of period	**$ -**	$ -	**$ -**	$ -
Interest paid	**$ 3,492**	$ 3,768	**$ 14,550**	$ 19,097
Taxes paid	**-**	-	**-**	-

See accompanying notes

NOTES TO INTERIM CONSOLIDATED FINANCIAL STATEMENTS

(dollar amounts in $ thousands Cdn except as noted)

1. BASIS OF PRESENTATION AND ACCOUNTING POLICIES

These interim consolidated financial statements of Paramount Energy Trust ("PET" or "the Trust") have been prepared by management under the successful efforts method of accounting in accordance with Canadian generally accepted accounting principles ("GAAP") following the same accounting principles and methods of computation as the consolidated financial statements for the year ended December 31, 2008. Certain disclosures provided below are incremental to those included with the annual consolidated financial statements. The specific accounting principles used are described in the annual consolidated financial statements of the Trust appearing on pages 31 through 37 of the Trust's 2008 annual report and should be read in conjunction with these interim financial statements.

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. This accounting pronouncement did not result in any changes to the Trust's financial statements.

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 the expensing of acquisition costs, 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 non-controlling interest 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 of the result between the controlling interest and non-controlling interest outside of the income statement. 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. PET has not early adopted Section 1582 as at September 30, 2009.

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, however, as the Trust currently reports under successful efforts, it is anticipated that the transition to IFRS will result in less of an impact than that for a full cost oil and gas reporting entity. The Trust will continue to monitor any changes on the path of adoption of IFRS and will update its conversion plan as necessary.

Financial Instruments

In May 2009, the CICA amended Section 3862, "Financial Instruments – Disclosures," to include additional disclosure requirements about fair value measurement for financial instruments and liquidity risk disclosures. These amendments require a three level hierarchy that reflects the significance of the inputs used in making the fair value measurements.

Fair values of assets and liabilities included in Level 1 are determined by reference to quoted prices in active markets for identical assets and liabilities. Assets and liabilities in Level 2 include valuations using inputs other than quoted prices for which all significant outputs are observable, either directly or indirectly. Level 3 valuations are based on inputs that are unobservable and significant to the overall fair value measurement. These amendments are effective for the Trust on December 31, 2009.

2. PROPERTY, PLANT AND EQUIPMENT

	September 30, 2009	December 31, 2008
Petroleum and natural gas properties	**$ 2,199,616**	$ 2,051,890
Asset retirement costs	**157,070**	154,720
Corporate assets	**4,833**	4,205
	2,361,519	2,210,815
Accumulated depletion and depreciation	**(1,384,498)**	(1,256,662)
	$ 977,021	$ 954,153

Property, plant and equipment at September 30, 2009 included $135.6 million (December 31, 2008 - $126.8 million) currently not subject to depletion and $26.8 million (December 31, 2008 - $26.8 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. See note 3 for the impact of an acquisition on property, plant & equipment as at September 30, 2009.

3. PROFOUND ACQUISITION

On June 30, 2009, pursuant to a takeover offer announced on March 31, 2009, the conversion of previously issued special warrants and open market purchases, PET acquired 67.3 percent of the outstanding common shares and thereby gained control of Profound Energy Inc. ("Profound"). On August 13, 2009 PET completed the second stage of the announced transaction, acquiring the remaining 32.7 percent of Profound's outstanding shares. The Trust paid $19.8 million for this additional ownership of Profound, reducing non-controlling interest by $45.4 million and property plant and equipment by $28.1 million while increasing the asset retirement obligation by $0.6 million and the future income tax asset by $3.1 million. Cash consideration paid for Profound consisted of $6.9 million for the special warrants, $3.1 million for the open market share purchases and $14.4 million for the tendered shares on June 30, 2009 and August 13, 2009, and $3.1 million of acquisition costs for a total of $27.5 million. In addition, PET issued 10 million Trust Units to Profound shareholders valued at $32.0 million, using PET's weighted average unit trading price for the five trading days surrounding the announcement date of $3.21 per Trust Unit. The acquisition was accounted for using the purchase method of accounting. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition, using a combination of fair values of the acquired assets and assumed liabilities at both June 30, 2009 and August 13, 2009. The Trust has not yet finalized its determination of the assets acquired and the liabilities assumed, and therefore the purchase price and the allocation of such to the acquired assets and liabilities are subject to change.

Cash consideration	$ 24,407
Trust Units issued	32,008
Acquisition costs	3,053
Total consideration	$ 59,468
Property, plant and equipment	$ 101,478
Future tax asset	13,811
Accounts receivable	6,686
Financial instruments	814
Accounts payable and accrued liabilities	(6,324)
Bank debt	(52,449)
Asset retirement obligation	(4,548)
Net assets acquired	$ 59,468

4. 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.

5. BANK DEBT

PET has a revolving credit facility with a syndicate of Canadian chartered banks (the "Credit Facility"). With the persistent weakness in natural gas prices in 2009, lenders have significantly reduced the natural gas price forecasts used in their credit evaluations. As a result PET expects that the borrowing base under the Credit Facility will be reduced by approximately 10 percent in the next few weeks following the completion of the semi-annual borrowing base review by the Lenders. The revolving nature of the facility expires on May 24th, 2010 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. In addition to amounts outstanding under the Credit Facility, PET has outstanding letters of credit in the amount of $12.7 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 borrowing 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 September 30, 2009 was 3.8 percent.

During the three months ended September 30, 2009, the Trust repaid and terminated Profound's revolving credit facility.

In addition, Severo has a 364 day extendible first senior revolving credit facility with a Canadian Chartered bank in the amount of $10 million. The facility has been renewed to April 30, 2010. At September 30, 2009 Severo had $7.8 million drawn on the facility.

6. 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.

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.

On October 14, 2009, the Trust announced that it intends to seek debenture holder approval to combine and amend the terms of the 2005 6.25% and 2006 6.25% Debentures. The proposed changes to the terms include an increase of the coupon rate by 0.50% to 6.75%, reduction of the conversion price to $8.40, extension of the maturity date to October 31, 2016 and provision of a four year non-call ending on October 31, 2013. The Trust has scheduled a meeting of debentureholders on November 13, 2009 to approve the amendments.

The Trust's 8% convertible unsecured subordinated debentures ("8% Convertible Debentures") matured and were paid out in cash on September 30, 2009.

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 Amount	2005 6.25% Series Amount	2006 6.25% Series Amount	6.5% Series Amount	Total Amount
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	1,965
Converted to 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
Accretion of non-cash equity component	-	88	548	375	1,011
Amortization of debenture issue fees	18	330	645	448	1,441
Repayment of principal on maturity	(5,866)	-	-	-	(5,866)
Short term balance, September 30, 2009	**-**	**$ 55,131**	**-**	**-**	**$ 55,131**
Long term balance, September 30, 2009	**-**	**-**	**$ 97,170**	**$ 71,651**	**$ 168,821**
Market value, September 30, 2009	-	$ 55,271	$ 98,972	$ 71,404	$ 225,647
Principal amount of debentures outstanding, September 30, 2009	-	55,271	99,972	74,925	230,168

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

Balance, as at December 31, 2007	$ 7,338
Conversion of Trust Units	(3)
Balance, as at December 31, 2008 and September 30, 2009	**$ 7,335**

7. 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, 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
Units issued pursuant to Unit Incentive Plan	136,125	1,138
Units issued pursuant to Bonus Rights Plan	55,115	268
Units issued pursuant to Dividend Reinvestment Plan	685,959	3,002
Units issued pursuant to Optional Cash Payments	138,200	620
Units issued pursuant to Profound acquisition	9,971,460	32,008
Balance, September 30, 2009	**123,954,642**	**$ 1,145,489**

c) Per Unit Information

Basic per unit amounts are calculated using the weighted average number of Trust Units outstanding during the three and nine months ended September 30, 2009 of 121,452,176 and 115,861,258 (2008 – 111,782,682 and 111,005,063 respectively). 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 per unit amounts for the three and nine months ended September 30, 2009, 1,096,804 and 736,850 Trust Units were added to the basic weighted average number of Trust Units outstanding (2008 – 1,434,959 and 1,450,642 Trust Units respectively) for the dilutive effect of incentive rights, bonus rights and convertible debentures. In computing diluted per unit amounts for the three and nine month periods ended September 30, 2009, 6,391,428 and 6,751,382 incentive and bonus rights respectively, as well as 12,746,394 potentially issuable Trust Units through the Convertible Debentures (see note 6) were excluded as the exercise and conversion prices were out of the money at September 30, 2009 (for three and nine months ended September 30, 2008 –3,407,500 incentive rights, 12,751,675 potentially issuable Trust Units through the Convertible Debentures).

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) Premium Distribution Reinvestment Plan

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

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

8. INCENTIVE PLANS

a) Unit Incentive Plan

PET has in place a Unit Incentive Plan ("Unit Incentive Plan") which permits the Administrator's Board of Directors to grant nontransferable 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 administers the Unit Incentive Plan and determines 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. The exercise price of the Incentive Rights ("Exercise Price") is, 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. 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. 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 three and nine month periods ended September 30, 2009 the Trust recorded $ 3.2 million and $ 6.3 million respectively in Trust Unit compensation ($1.2 million and $4.2 million respectively for the three and nine month periods ended September 30, 2008).

At September 30, 2009 PET had 7.5 million Unit Incentive and Bonus Rights issued and outstanding relative to the 12.4 million (10 percent) of total Trust Units outstanding reserved under the Unit Incentive and the Bonus Rights Plans (see note 7 (b)). As at September 30, 2009, 947,750 Incentive Rights granted under the Unit Incentive Plan had vested but were unexercised (1,015,875 as of September 30, 2008).

During the quarter, the Board of Directors approved the cancellation of 2,521,375 Incentive Rights and as a result, $2.1 million was included in Trust Unit based compensation expense.

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
	2009	2008
Distribution yield (%)	**0.0**	0.0
Expected volatility (%)	**45.4 – 51.6**	30.0 – 32.0
Risk-free interest rate (%)	**1.56 – 2.22**	2.66 – 3.46
Expected life of Incentive Rights (years)	**3.75 – 4**	3.75
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	**1.63**	2.37

Incentive Rights	**Average exercise price**	**Incentive rights**
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
Granted	4.34	3,183,250
Exercised	4.04	(136,125)
Cancelled	12.86	(2,512,375)
Forfeited	7.56	(759,875)
Balance, September 30, 2009	**$ 4.82**	**7,201,375**

The following table summarizes information about Incentive Rights outstanding at September 30, 2009 assuming the reduced exercise price described on previous page:

Range of exercise prices	Number outstanding at September 30, 2009	Weighted average contractual life (years)	Weighted average exercise price/Incentive Right	Number exercisable at September 30, 2009	Weighted average exercise price/Incentive Right
$2.98 - $7.53	6,364,875	3.9	$ 4.23	799,625	$ 4.53
$7.54 - $8.33	126,500	2.8	7.54	63,250	7.54
$8.34 - $14.35	697,500	2.7	9.65	72,375	9.38
$14.36 - $22.70	12,500	0.3	16.15	12,500	16.15
Total	7,201,375	3.7	$ 4.82	947,750	$ 5.26

A reconciliation of contributed surplus is provided below:

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
Trust Unit-based compensation expense	6,345
Transfer to Unitholders' capital on exercise of Incentive Rights	(580)
Transfer to Unitholders' capital on exercise of Bonus Rights	(268)
Balance, as at September 30, 2009	**$ 18,370**

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 three and nine month periods ended September 30, 2009, $0.1 and $0.8 million compensation expense was recorded in respect of the Bonus Rights granted (three and nine month period ended September 30, 2008 - $0.9 million).

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

	Bonus Rights
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
Granted	151,684
Exercised	(55,115)
Additional grants for accrued distributions	28,439
Balance, September 30, 2009	**286,858**

9. 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 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 $ 191.8 million as at September 30, 2009 based on an undiscounted total future liability of $ 388.9 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 percent to calculate the present value of the asset retirement obligation.

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

	September 30, 2009	December 31, 2008
Obligation, beginning of year	**$ 179,723**	$ 194,132
Obligations acquired	**7,887**	-
Obligations incurred	**1,635**	3,523
Obligations disposed	**(5,559)**	(4,695)
Revisions to estimates	**-**	(21,915)
Expenditures for obligations during the period	**(2,913)**	(5,226)
Accretion expense	**11,035**	13,904
	$ 191,808	$ 179,723

10. 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 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 establish marketing relationships with large, well established purchasers. 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 industry factors such as commodity price fluctuations, escalating costs, 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. The Trust manages the credit exposure related to financial instruments by engaging in hedging transactions with counterparties with investment grade credit ratings, and periodically monitoring the changes in such credit ratings.

During the period credit risk did not have any impact on the change in 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 September 30, 2009 is $4.5 million. The amount of the allowance was determined by assessing the probability of collection for each past due receivable. The Trust is currently involved in negotiations with the seller and the joint venture partners involved in an effort to recover the full amount of the receivables in question. The total amount of receivables past due 90 days amounted to $9.0 million as at September 30, 2009. As at the balance sheet date, as a mitigating factor to the credit exposure, the Trust has $2.8 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 5. 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 September 30, 2009:

Contractual repayments of financial liabilities	**Total**	**2009**	**2010**	**2011-2013**	**Thereafter**
Accounts payable and accrued liabilities	$ 24,834	$ 24,834	$ -	$ -	$ -
Distributions payable	6,197	6,197	-	-	-
Current bank debt – principal	7,763	-	7,763	-	-
Long term bank debt – principal	291,017	-	-	291,017	-
Convertible debentures – principal (1)	230,168	-	55,271	174,897	-
Total	$ 559,979	$ 31,031	63,034	$ 465,914	$ -

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

Interest payments on financial liabilities	**Total**	**2009**	**2010**	**2011-2013**	**Thereafter**
Interest payment on bank debt (1)	$ 18,610	$ 2,850	$ 11,279	$ 4,481	$ -
Interest on convertible debentures (2)	25,877	3,643	12,846	9,388	-
Total	$ 44,487	$ 6,493	$ 24,125	$ 13,869	$ -

(1) Assuming revolving feature of the credit facility is not extended and calculated at the September 30, 2009 effective interest rate of 3.8% and assuming a constant debt level equivalent to the balance at September 30, 2009.

(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 fixed price 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 uses foreign exchange contracts to mitigate the effects of fluctuations in exchange rates on the Trust's cash flows. The Trust does not consider its direct exposure to foreign currency exchange rate risk to be significant; refer to commodity price risk analysis below.

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 60 percent of forecasted production volumes including gas over bitumen deemed production, as outlined in the Trust's risk management policy.

As at September 30, 2009, 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 nine month period ended September 30, 2009 forward physical gas fixed-price sales contracts resulted in realized gains of $1.3 million that have been included in oil and natural gas revenue ($0.9 million loss for the nine month period ended September 30, 2008). In order to calculate these realized gains, PET compares the fixed price received to the AECO monthly index price and the NYMEX index.

Realized gains on financial instruments, including financial natural gas commodity contracts recognized in net earnings (loss) for three and nine month periods ended September 30, 2009 were $56.3 million and $145.9 million respectively ($0.9 million and $9.9 million losses for the three and nine month periods ended September 30, 2008). Of the total realized gains on financial instruments, included in earnings for three and nine month periods ended September 30, 2009, $41.4 and $89.1 million, respectively, were recorded as a result of settlement of contracts prior to maturity ($11.2 and 13.0 million for three and nine month periods ended September 30, 2008). Unrealized loss on financial instruments of $45.8 million for the three month period ended September 30, 2009 was mostly a result of settlements of contracts prior to maturity.

Natural gas commodity contracts

At September 30, 2009 the Trust had entered into forward gas sales arrangements at AECO as follows:

Type of contract	PET sold/bought	Volumes at AECO (GJ/d)	Price ($/GJ)			Term
			Fixed	Floor	Ceiling	
Financial	sold	145,000	$ 3.993	-	-	October 2009
Physical	sold	7,500	$ 5.763	-	-	October 2009
Physical	bought	(7,500)	$ 7.147	-	-	October 2009
Financial	sell	2,500	-	$ 4.750	$ 6.250	October–December 2009
Financial	sell	1,000	-	$ 5.000	$ 7.550	October 2009 – March 2010
Financial	sold	110,000	$ 5.762	-	-	November 2009 – March 2010
Financial	bought	(12,500)	$ 5.550	-	-	November 2009 – March 2010
Financial	sold	107,500	$ 7.243	-	-	April – October 2010
Financial	sold	107,500	$ 7.775	-	-	November 2010 – March 2011
Physical	sold	10,000	$ 7.745	-	-	November 2010 – March 2011
Financial	sold	50,000	$ 6.329	-	-	April – October 2011
Financial	sold	89,679	$ 6.777	-	-	January 2013 – March 2013

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 and $4.3 million in upfront premiums in 2008 and 2009 respectively. Call option premiums received are classified separately in the statement of earnings and are included in the calculation of the Trust's cash flow provided by operating activities. Mark to market values of the call options are included in the unrealized gains on financial instruments in the statement of earnings.

Type of contract	PET sold/bought	Volumes at AECO (GJ/d)	Price ($/GJ)			Term
			Fixed	Floor	Ceiling	
Financial	sold	5,000	-	-	$ 8.500	November 2009 – March 2010
Financial	sold	20,000	-	-	$ 7.250	January – December 2010
Financial	sold	5,000	-	-	$ 7.750	April – October 2010
Financial	sold	22,500	-	-	$ 8.222	November 2010 – March 2011

At September 30, 2009 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	2,500	$ 3.725	October 2009
Financial	bought	(2,500)	$ 3.495	October 2009
Financial	sold	12,500	$ 4.210	November 2009
Financial	bought	(10,000)	$ 4.265	November 2009

At September 30, 2009 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. Physical basis contracts represent commitments rather than contractual obligations.

Type of Contract	PET sold/bought	Volumes at NYMEX (MMBTU/d)	Price (US$/MMBTU)	Term
Financial	sold	12,500	$ (0.803)	October 2009
Financial	bought	(12,500)	$ (0.811)	October 2009
Physical	sold	10,000	$ (0.748)	October 2009
Physical	bought	(10,000)	$ (0.760)	October 2009
Financial	sold	32,500	$ (0.693)	November 2009 – March 2010
Financial	bought	(25,000)	$ (0.805)	November 2009 – March 2010
Physical	sold	30,000	$ (0.673)	November 2009 – March 2010
Financial	sold	7,500	$ (0.695)	November 2009 – March 2010
Financial	sold	5,000	$ (0.770)	April – October 2010
Financial	bought	(5,000)	$ (0.810)	April – October 2010
Physical	sold	17,500	$ (0.445)	April – October 2010
Physical	bought	(17,500)	$ (0.731)	April – October 2010
Financial	sold	2,500	$ (0.680)	November 2010 – March 2011
Financial	bought	(2,500)	$ (0.845)	November 2010 – March 2011
Financial	sold	15,000	$ (0.547)	April – October 2011
Financial	bought	(15,000)	$ (0.550)	April – October 2011

The following table reconciles the Trust's financial instrument assets and liabilities as at September 30, 2009:

	Current Financial Instrument Asset (Liability)	Long Term Financial Instrument Asset (Liability)	Total
Balance at December 31, 2008	$ 45,262	$ 13,406	$ 58,668
Unrealized (loss)/gain, excluding option premiums	(12,039)	12,014	(25)
Acquired from Profound	814	-	814
Balance at September 30, 2009	**$ 34,037**	**$ 25,420**	**$ 59,457**

Commodity price sensitivity analysis

As at September 30, 2009, 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, unrealized gains on financial instruments and after tax net earnings for the period would have changed by $19.7 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, due to the effect of the mark-to-market value of the Trust's financial instruments on earnings.

Mark to market sensitivity was based on published forward AECO and NYMEX prices. Gains and losses on NYMEX contracts were calculated based on the $US foreign exchange rate as at September 30, 2009.

Interest rate risk

The Trust utilizes a long-term debt credit facility which bears a floating rate of interest and as such is 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 September 30, 2009.

Interest rate sensitivity analysis

For period three months ended September 30, 2009, if interest rates had been one percent lower or higher the impact on earnings would be as follows:

Interest rate sensitivity ($ thousands)	1% increase	1% decrease
(Decrease)increase in net earnings	$ (700)	$ 700

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 one 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 2009 from prior reporting periods. The Trust intends to seek debenture holder approval to amend and extend certain series of convertible debentures (see Note 6).

The Trust monitors capital based on the ratio of net debt to annualized funds flow, calculated as follows for the three months ended September 30, 2009:

Net debt ($ thousands)	**September 30, 2009**
Bank debt	**$ 298,780**
Convertible debentures, measured at principal amount	**$ 230,168**
Working capital deficiency (surplus) (2)	**$ (3,231)**
Net debt	**$ 525,717**
Cash flow provided by operating activities	**$ 54,579**
Exploration costs (3)	**$ 1,218**
Expenditures on asset retirement obligations	**$ 483**
Changes in non-cash operating working capital	**$ 3,319**
Funds flow	**$ 59,599**
Annualized funds flow (1)	**$ 238,396**
Net debt to annualized funds flow ratio (times) (1)	**2.21**

1) These are non-GAAP measures; see "Significant accounting policies and non-GAAP measures" in management's discussion and analysis.

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

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 September 30, 2009, the Trust's ratio of net debt to annualized funds flow was 2.21 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 September 30, 2009.

The capital structure at September 30, 2009 was as follows:

Net debt	$ 525,717
Total equity (net of deficit) (1)	268,611
Non-controlling interest	1,583
Total capital at September 30, 2009	$ 795,911

1) As at September 30, 2009 the closing market price of Paramount Energy Trust's Units was $5.30.

Fair value of financial instruments

The Trust's financial instruments as at September 30, 2009 and December 31, 2008 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 exchange 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.

11. OPERATING LEASES

a) Operating leases

As of September 30, 2009, the future minimum payments under office lease costs and related sublease recoveries under contractual agreements consisted of:

Operating leases	
2009	897
2010	3,597
2011	1,374
2012	646
After 2013	54
Total commitment	$ 6,568

b) Pipeline commitments

The Trust has long-term commitments to pay for gas transportation on certain major pipeline systems in western Canada. As of September 30, 2009, the future minimum payments under pipeline commitments under contractual agreements consisted of:

Pipeline commitments	
2009	1,936
2010	5,657
2011	2,783
2012	1,826
After 2013	2,586
Total commitment	$ 14,788

12. 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 Energy Resources Conservation Board (the "ERCB") 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.

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.

For the three and nine month periods ended September 30, 2009 PET had received $1.9 million and $7.1 million respectively ($6.0 million and $16.5 million for the three and nine month periods ended September 30, 2008) for gas over bitumen royalty adjustments. Of this amount, for the three and nine month periods ended September 30, 2009 $0.3 million and $1.1 million respectively has been recorded as revenue and $1.6 million and $6.0 million has been recorded on the Trust's balance sheet (three and nine month periods ended September 30, 2008 $1.0 million and $2.9 million as revenue and $5.0 million and $13.6 million on the Trust's balance sheet, respectively).

13. SUBSEQUENT EVENT

On October 16, 2009, the ERCB issued Decision 2009-061 in response to applications by Sunshine Oilsands Ltd. and Total E&P Canada Ltd. for the shut-in of gas in the Liege Field within the Athabasca Oil Sands Area. Having considered the evidence submitted to an interim hearing, the ERCB concluded that production of gas from 228 intervals in 158 wells may present a significant risk to future bitumen recovery, pending the outcome of the full hearing of the applications. The Board also decided to shut in gas on an interim basis from 51 additional intervals in the Liege Wabiskaw A Pool, 15 additional intervals in the Liege Leduc A Pool, two additional intervals in the Liege Wabiskaw O Pool, and one additional interval in the Liege Wabiskaw M Pool.

The ERCB ordered the interim shut-in of gas production effective October 31, 2009. Production from these intervals shall remain shut in pending the ERCB's final decision regarding Applications No. 1613543 and 1616123 (the "Applications"). Because this was an interim proceeding, the ERCB did not have the benefit of the entirety of the evidence and argument that will ultimately be made available, nor was the ERCB in a position to assess the merits based on the totality of evidence. Accordingly, the ERCB advised that the interim decision should not be considered as conclusive or permanent with regard to the issues to be addressed at the full hearing. The schedule put forth by the ERCB accommodates a full hearing on this matter to be held in the fourth quarter of 2010.

PET has 70 wells that are specifically named for interim shut-in. An additional 18 wells have been shut-in due to the shut-in of facilities in the area. PET has applied for the royalty reductions provided in the Royalty Regulation for gas production shut in pursuant to this ERCB decision.

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Susan L. Riddell Rose
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Randall E. (Randy) Johnson
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John W. (Jack) Peltier
Independent Director (1) (2) (4)

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

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

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Vice President, Marketing

Roderick (Rick) P. Warters
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Corporate Secretary, Corporate Counsel

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