Maximizing distributions and Unitholder value

Q2

SECOND QUARTER INTERIM REPORT
For the six months ended June 30, 2006

PARAMOUNT ENERGY TRUST

Highlights

Asset Optimization

- During the second quarter, 30 gross (14 net) wells were drilled with a 99% success rate.
- The Trust disposed of certain assets that were shut-in as a result of the Alberta Energy and Utilities Board ("AEUB") gas over bitumen decisions for proceeds of $12.7 million, but retained the right to receive the related monthly gas over bitumen royalty adjustment.
- PET plans to spend up to $20 million on exploration and development prior to year end, including up to 38 additional wells.

Accretive Acquisitions

- AcquireCo's management team worked with PET through to the end of June in executing value-added capital projects on the east central Alberta lands and developing new prospects that matched PET's risk profile. Up to 21 additional wells are planned on these assets prior to year end and a significant capital program is being further delineated for 2007.

Maximize Cash Flow

- Cash flow for the second quarter measured $56.6 million as compared to $66.5 million for the second quarter of 2005. Cash flows were adversely affected by lower natural gas prices as a result of significant weakness in North American natural gas markets, offset somewhat by higher production volumes.
- Average production increased to a record 162.9 MMcf/d for the three months ended June 30, 2006, a ten percent increase from 148.5 MMcf/d in the second quarter of 2005.
- Significant financial hedging and physical forward sales contracts mitigated the negative effect of relatively weak natural gas prices on second quarter 2006 cash flow. The Trust realized a natural gas price of $6.85 per Mcf in the second quarter of 2006, 12 percent higher than the Alberta Gas Reference Price of $6.12 per Mcf for the same period.
- The Trust continued to supplement its hedging and physical forward sales portfolio in light of current weakness in natural gas prices. PET's weighted average price on financial hedges and physical forward sales contracts for an average of 86,700 GJ/d for the period from July 1 to December 31, 2006 is $7.90 per GJ. Further price management is in place for the next 2 years.

Balance Sheet

- PET closed the previously-announced offering of $100 million of 6.25% convertible debentures on April 6, 2006.
- During the second quarter, PET's industry-leading DRIP Plan contributed $6.0 million.
- The Trust's bank borrowing base is $310 million, with current bank debt drawn to $231 million.

Maximize Distributions and Unitholder Value

- Distributions for the second quarter of 2006 totaled $0.72 per Trust Unit.
- Given the current weakness in natural gas prices, PET elected to manage its business strategy of sustainability by reducing the monthly distribution to $0.20 per Trust Unit effective with the July distribution. The reduction allows the Trust to continue with its ongoing highly profitable capital programs while ensuring that distributions plus capital spending are less than cash flow.

Canada's leading 100% natural gas royalty trust.

PARAMOUNT ENERGY TRUST ("PET" or "the Trust") is a natural gas focused Canadian energy royalty trust which commenced operations in February 2003. PET was formed with the vast majority of the shallow natural gas properties in northeast Alberta discovered and developed by Paramount Resources Ltd. The characteristics of those assets are well suited to a trust; predictable production performance, high field netbacks, an extensive opportunity inventory, a history of low cost production additions, high working interest, operatorship and strategic infrastructure ownership.

We have substantially increased production and reserves through a series of property acquisitions which added geographic diversification, while maintaining the key characteristics of our shallow gas asset base. As operators of 90 percent of our asset base, we are hands-on managers of our capital programs, operating costs, production and gas marketing. All of our efforts are directed to maximizing returns to Unitholders.

Financial and operating highlights

($Cdn thousands except volume and per Trust Unit amounts)	Three Months Ended June 30 **2006**	2005	% change	Six Months Ended June 30 **2006**	2005	% change
Financial						
Revenue, including realized gains (losses) on financial instruments (1)	**101,580**	100,234	1	**211,955**	176,580	20
Cash flow (1)	**56,605**	66,491	(15)	**117,717**	107,292	10
Per Trust Unit (2)	**0.68**	0.90	(24)	**1.41**	1.54	(8)
Net earnings	**21,816**	11,433	91	**29,785**	13,632	118
Per Trust Unit (2)	**0.26**	0.16	63	**0.36**	0.20	80
Distributions	**60,284**	48,302	25	**120,238**	91,904	31
Per Trust Unit (3)	**0.72**	0.66	9	**1.44**	1.32	9
Payout ratio (%) (1)	**106.5**	72.6	47	**102.1**	85.7	19
Total assets	**896,611**	850,233	5	**896,611**	850,233	5
Net bank and other debt outstanding (4)	**231,210**	223,996	3	**231,210**	223,996	3
Convertible debentures	**157,572**	132,641	19	**157,572**	132,641	19
Total net debt (4)	**388,782**	356,637	9	**388,782**	356,637	9
Unitholders' equity	**330,590**	363,365	(9)	**330,590**	363,365	(9)
Cumulative distributions since inception (1)	**569,786**	336,420	69	**569,786**	336,420	69
Unitholders' equity before distributions (1)	**900,376**	699,785	29	**900,376**	699,785	29
Capital expenditures						
Exploration and development	**10,466**	4,384	139	**90,767**	44,612	103
Acquisitions, net of dispositions	**(11,866)**	256,789	(105)	**77,546**	283,587	(73)
Other	**412**	135	205	**522**	285	83
Net capital expenditures	**(988)**	261,308	(100)	**168,835**	328,484	(49)
Trust Units outstanding (thousands)						
End of period	**83,857**	76,881	9	**83,857**	76,881	9
Weighted average	**83,663**	73,558	14	**83,387**	69,717	20
Incentive and Bonus Rights outstanding	**1,944**	1,673	16	**1,944**	1,673	16
Trust Units outstanding at August 8, 2006	**84,023**					
Operating						
Production						
Total natural gas (Bcf) (5)	**14.8**	13.5	10	**28.5**	24.5	16
Daily average natural gas (MMcf/d) (5)	**162.9**	148.5	10	**157.2**	135.3	16
Gas over bitumen deemed production (MMcf/d) (6)	**21.5**	23.1	(7)	**21.5**	23.3	(8)
Average daily (actual and deemed - MMcf/d) (6)	**184.4**	171.6	7	**178.7**	158.6	13
Per Trust Unit (cubic feet/d/Unit) (2)	**2.20**	2.33	(6)	**2.14**	2.27	(6)
Average natural gas prices ($/Mcf)						
Before financial hedging and physical forward sales(7)	**6.16**	7.41	(17)	**6.91**	7.06	(2)
Including financial hedging and physical forward sales	**6.85**	7.42	(8)	**7.45**	7.21	3
Land (thousands of net acres)						
Undeveloped land holdings	**1,084**	1,139	(5)	**1,084**	1,139	(5)
Drilling (gross / net)						
Gas	**29/13.7**	17/3.2	71/328	**113/87.0**	51/31.0	122/181
Dry	**1/0.2**	1/1.0	-/(80)	**4/1.9**	4/4.0	-/(53)
Total	**30/13.9**	18/4.2	67/231	**117/88.9**	55/35.0	113/154
Success rate (% gross / % net)	**97/99**	94/76	3/30	**97/98**	93/89	4/10

(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 related to the Trust's natural gas hedging activities. Total net debt includes convertible debentures.

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

(6) The Trust had 24.7 MMcf/d of natural gas production shut-in or denied production pursuant to various Alberta Energy and Utilities Board ("AEUB") decision reports, corresponding shut-in orders or general bulletins or through correspondence in relation to an AEUB ID 99-1 application on, or prior to July 1, 2004. Deemed Production is not actual gas sales but represents shut-in gas that is the basis of the gas over bitumen financial solution during the period which is received monthly from the Alberta Crown as a reduction against other royalties payable.

(7) 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 daily index.

Summary

In the second quarter of 2006 PET concentrated on integrating the AcquireCo assets into its existing operational structure and bringing on additional natural gas production from its substantial winter capital program. Production for the second quarter of 2006 totaled 162.9 MMcf/d, a ten percent increase from the second quarter of 2005. Strong results from the winter capital program and the addition of the AcquireCo Assets to the Trust's portfolio of primarily PET-operated, high-netback 100% natural gas properties contributed to the production increase.

PET focused second quarter capital expenditures on year-round access properties in its Southern core area including the AcquireCo assets. Exploration and development expenditures for the quarter totaled $10.5 million including the drilling of 30 wells (13.9 net) with a 99 percent net success rate. The Trust participated in 12 gross (2.3 net) wells targeting coalbed methane and shallow sand reservoirs in the Craigmyle area of southern Alberta with the remainder of the drilling program primarily focused in east central Alberta. PET plans to spend up to an additional $20 million on capital projects in the Trust's all-weather access properties in the Southern and East Side core areas in the last two quarters of 2006 targeting low-risk production additions to further enhance the sustainability of the Trust's monthly distribution.

Cash flow for the second quarter measured $56.6 million as compared to $66.5 million for the second quarter of 2005. Cash flows were adversely affected by lower natural gas prices as a result of significant weakness in North American natural gas markets, offset somewhat by higher production volumes. Cash flow in the comparable period in 2005 also benefited from $4.8 million in retroactive gas over bitumen royalty adjustments received during the quarter.

PET reduced its monthly distribution to $0.20 per Trust Unit from $0.24 per Trust Unit effective for the July monthly distribution to be paid on August 15, 2006. PET adheres to a business strategy of sustainability where the sum of exploration and development capital expenditures and distributions is equal to or less than cash flow. PET's model for sustainability of its previous distribution of $0.24 per Trust Unit per month was based on an average annual gas price assumption of $8.00 per gigajoule ("GJ") at AECO. Due to the recent unprecedented high inventory of natural gas in North American gas storage and other factors the average price for natural gas sales at AECO in the second quarter of 2006 was approximately $5.95 per GJ, the forward market for natural gas sales for September through October of 2006 is currently trading at approximately $6.99 per GJ at AECO, and November through December of 2006 is trading at approximately $9.76 per GJ at AECO, significantly below the Trust's hedging levels and target gas price for sustaining a $0.24 monthly distribution. While the Trust's current hedging and physical forward sales portfolio has significantly reduced PET's exposure to short term downside in natural gas prices as the forward market for natural gas has weakened significantly over the last several months, the unhedged portion of the Trust's production has experienced a corresponding significant reduction in expected 2006 cash flow, which prompted an examination of the Trust's remaining 2006 capital programs and distribution levels. A detailed review of the ongoing capital programs confirmed that the Trust's projects remain highly profitable at both current and future gas price levels as suggested by the forward market. As a result of this analysis, the Trust has elected to maintain its capital investment programs and manage sustainability by reducing the monthly distribution. The forward market for natural gas sales in 2007 and 2008 is currently trading at an average annual price of $8.83 and $8.35 per GJ at AECO respectively.

The issuance of $100 million convertible debentures in April 2006 strengthened the Trust's balance sheet, allowing for continued participation in the acquisitions market should opportunities arise that meet PET's acquisition criteria. Through the Trust's industry-leading Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan") $6.0 million was invested by Unitholders during the current quarter, further contributing to PET's relatively conservative leverage position at June 30, 2006.

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 six months ended June 30, 2006 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 consolidated financial statements and accompanying notes for the three and six months ended June 30, 2006 and 2005 as well as the Trust's consolidated financial statements and accompanying notes and MD&A for the years ended December 31, 2005 and 2004. 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 August 8, 2006.

Second quarter highlights

	Three months ended June 30			Six months ended June 30		
($Cdn millions except per Trust Unit, percent and volume data)	**2006**	2005	% change	**2006**	2005	% change
Cash flow [1]	**$ 56.6**	$ 66.5	(15)	**$ 117.7**	$ 107.3	10
Per Trust Unit	**$ 0.68**	$ 0.90	(24)	**$ 1.41**	$ 1.54	(8)
Net earnings	**$ 21.8**	$ 11.4	91	**$ 29.8**	$ 13.6	118
Per Trust Unit	**$ 0.26**	$ 0.16	63	**$ 0.36**	$ 0.20	80
Distributions	**$ 60.3**	$ 48.3	25	**$ 120.2**	$ 91.9	31
Per Trust Unit	**$ 0.72**	$ 0.66	9	**$ 1.44**	$ 1.32	9
Payout ratio (%) [1]	**106.5**	72.6	47	**102.1**	85.7	19
Production (MMcf/d) [2]						
Daily average	**162.9**	148.5	10	**157.2**	135.3	16
Gas over bitumen deemed	**21.5**	23.1	(7)	**21.5**	23.3	(8)
Total average daily (actual and deemed)	**184.4**	171.6	7	**178.7**	158.6	13

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

(2) Production amounts are based on company interest before royalties.

Operations

Production

Natural gas production by core area (MMcf/d)	Three months ended June 30 2006	2005	Six months ended June 30 2006	2005
West Side	**48.5**	45.1	**47.0**	40.3
East Side	**28.4**	31.1	**27.5**	29.9
Athabasca	**73.7**	65.3	**71.9**	58.2
Southern	**12.3**	7.0	**10.8**	6.9
Total	**162.9**	148.5	**157.2**	135.3
Deemed production	**21.5**	23.1	**21.5**	23.3
Total actual plus deemed production	**184.4**	171.6	**178.7**	158.6

Average production increased ten percent to 162.9 MMcf/d for the three months ended June 30, 2006 as compared to 148.5 MMcf/d in the second quarter of 2005. The 11 percent increase in combined production in the West Side and Athabasca core areas is due primarily to the full effect of the acquisition of assets in Northeast Alberta in May 2005 (the "Northeast Alberta Acquisition") offset somewhat by natural production declines since the date of acquisition. Natural declines experienced throughout the last three quarters of 2005 in all northeast Alberta core areas were mitigated by winter drilling, recompletion and production optimization activities in the first quarter of 2006. The increase in production in the Southern core area is due to the acquisition of the AcquireCo assets in February 2006 as well as production increases from positive drilling results at Kirkpatrick and Craigmyle, offset somewhat by declines in west central and southwest Saskatchewan. Including the deemed production volume related to the gas over bitumen financial solution, average daily production (actual and deemed) increased seven percent to 184.4 MMcf/d from 171.6 MMcf/d in the second quarter of 2005.

Production for the six months ended June 30, 2006 increased 16 percent to 157.2 MMcf/d from 135.3 MMcf/d in the comparative period for 2005 largely as a result of the Northeast Alberta Acquisition, the acquisition of AcquireCo and a successful 2006 winter capital program.

Capital expenditures

Capital expenditures ($ thousands)	Three months ended June 30 2006	2005	Six months ended June 30 2006	2005
Exploration and development expenditures (1)	**$ 10,466**	$ 4,384	**$ 90,767**	$ 44,612
Acquisitions	**871**	257,825	**91,753**	284,623
Dispositions	**(12,737)**	(1,036)	**(14,207)**	(1,036)
Other	**412**	135	**522**	285
Total capital expenditures	**$ (988)**	$ 261,308	**$ 168,835**	$ 328,484

(1) Exploration and development expenditures for the three and six months ended June 30, 2006 include approximately $0.6 million and $8.9 million, respectively in exploration costs (three and six months ended June 30, 2005 – $9.6 million) which have been expensed directly on the Trust's statement of earnings. Exploration costs 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 a result they are included with capital expenditures.

Exploration and development expenditures for the three months ended June 30, 2006 totaled $10.5 million, as compared to $4.4 million in the comparative quarter for 2005. PET's capital spending for the quarter was concentrated on the east central Alberta properties obtained as a result of the AcquireCo purchase, the Trust's non-operated coalbed methane project at Craigmyle and certain year-round access properties in the southern portion of the Athabasca core area. In total 30 wells (13.9 net) were drilled with a 99 percent net success rate. In addition, eight out of nine wells drilled in east central Alberta prior to break up are in the process of being completed and tied in.

Dispositions of $12.7 million are primarily related to the sale of certain assets that were shut-in as a result of the AEUB's gas over bitumen decisions. As a condition of the transaction PET continues to receive the monthly gas over bitumen royalty adjustments related to the disposed assets, thereby realizing significant proceeds on disposition without any related loss in cash flow from the shut-in assets and without any future obligations should production from these assets recommence.

Marketing

Natural gas prices

Natural gas prices ($/Mcf, except percent amounts)	Three months ended June 30 2006	2005	Six months ended June 30 2006	2005
Reference prices				
AECO Monthly Index	**6.27**	7.38	**7.77**	7.03
AECO Daily Index	**6.03**	7.38	**6.77**	7.13
Alberta Gas Reference Price (1)	**6.12**	6.91	**7.17**	6.66
Average PET prices				
Before financial hedging and physical forward sales (2)	**6.16**	7.41	**6.91**	7.06
% Alberta Gas Reference Price (%)	**101**	107	**96**	106
Before financial hedging (3)	**6.60**	7.42	**7.40**	7.20
% Alberta Gas Reference Price (%)	**108**	107	**103**	108
After financial hedging and physical forward sales	**6.85**	7.42	**7.45**	7.21
% Alberta Gas Reference Price (%)	**112**	107	**104**	108

(1) Alberta Gas Reference Price is the price used to calculate Alberta Crown royalties. Alberta Gas Reference Price for June 2006 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 daily 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.

Realized natural gas prices decreased by eight percent for the three months ended June 30, 2006 to $6.85 per Mcf from $7.42 per Mcf in 2005 as compared to an 11 percent decrease in the Alberta Gas Reference Price for the same period. The decline in the Trust's realized gas price is less pronounced than the decline in AECO prices due to PET's commodity hedging program. PET's realized natural gas price was $7.45 per Mcf for the six months ended June 30, 2006 compared to $7.21 per Mcf for the same period in 2005.

Risk Management

To insure cash flow and distributions against commodity price volatility and to lock in attractive economics on acquisitions, the Trust maintains a balanced gas price risk management portfolio using both financial hedge arrangements and physical forward sales. PET estimates that realized natural gas revenues of $10.2 million for the second quarter of 2006 and $15.4 million for the first six months of 2006 can be attributed to the Trust's risk management program.

At June 30, 2006, the Trust had entered into financial and physical forward sales arrangements as follows:

Financial hedges and physical forward sales contracts at June 30, 2006

		Price ($/GJ)			
Type of Contract	Volumes at AECO (GJ/d)	Fixed	Floor	Ceiling	Term
Financial	40,000	$ 7.05			July – October 2006
Physical	29,500	$ 7.40			July – October 2006
Physical	5,000		$ 9.00	$ 12.50	July – October 2006
Period Total	74,500		$ 7.32(1)		July – October 2006
Financial	37,500	$ 9.12			November 2006 – March 2007
Financial	5,000		$ 9.00	$ 10.00	November 2006 – March 2007
Financial	5,000		$ 9.50	$ 11.00	November 2006 – March 2007
Physical	32,500	$ 9.05			November 2006 – March 2007
Physical	5,000		$ 8.50	$ 11.00	November 2006 – March 2007
Physical	5,000		$ 9.00	$ 10.00	November 2006 – March 2007
Physical	5,000		$ 9.00	$ 11.00	November 2006 – March 2007
Period Total	95,000		$ 9.06(1)		November 2006 – March 2007
Financial	37,500	$ 8.00			April – October 2007
Physical	40,000	$ 8.01			April – October 2007
Period Total	77,500		$ 8.00		April – October 2007
Financial	27,500	$ 9.56			November 2007 – March 2008
Physical	37,500	$ 9.69			November 2007 – March 2008
Period Total	65,000		$ 9.64		November 2007 – March 2008

(1) Average price calculated using fixed price and floor price for collars.

(2) AECO monthly index prices have settled for July and August; future index reflects AECO forward market prices as at August 9, 2006.

In addition, PET has entered into financial contracts to sell forward Canadian dollars for US dollars at a fixed exchange rate in order to mitigate the effect of exchange rate fluctuations on the Trust's realized natural gas price. Foreign exchange contracts outstanding as at June 30, 2006 are as follows:

Financial foreign exchange contracts at June 30, 2006

Type of Contract	CDN$ sold (monthly)	Fixed FX rate (CDN$/US$)	Term
Financial	$ 9,000,000	1.1349	July – October 2006
Financial	$ 13,000,000	1.1255	November 2006 – March 2007
Financial	$ 7,000,000	1.1242	April – October 2007
Financial	$ 11,000,000	1.1195	November 2007 – March 2008

PET continued to supplement its risk management program after the end of the second quarter. Financial and physical natural gas forward sales arrangements at August 9, 2006 are as follows:

Financial hedges and physical forward sales contracts at August 9, 2006

Type of Contract	Volumes at AECO (GJ/d)	Price ($/GJ) Fixed	Floor	Ceiling	AECO actual/future index ($/GJ) (2)	Term
Financial	40,000	$ 7.05				July 2006
Physical	29,500	$ 7.40				July 2006
Physical	5,000		$ 9.00	$ 12.50		July 2006
Period Total	74,500		$ 7.32(1)		$ 5.49	July 2006
Financial	40,000	$ 7.05				August 2006
Physical	37,000	$ 7.17				August 2006
Physical	5,000		$ 9.00	$ 12.50		August 2006
Period Total	82,000		$ 7.23(1)		$ 5.84	August 2006
Financial	40,000	$ 7.05				September – October 2006
Physical	42,000	$ 7.16				September – October 2006
Physical	5,000		$ 9.00	$ 12.50		September – October 2006
Period Total	87,000		$ 7.21(1)		$ 6.99	September – October 2006
Financial	37,500	$ 9.12				November 2006 – March 2007
Financial	5,000		$ 9.00	$ 10.00		November 2006 – March 2007
Financial	5,000		$ 9.50	$ 11.00		November 2006 – March 2007
Physical	32,500	$ 9.05				November 2006 – March 2007
Physical	5,000		$ 8.50	$ 11.00		November 2006 – March 2007
Physical	5,000		$ 9.00	$ 10.00		November 2006 – March 2007
Physical	5,000		$ 9.00	$ 11.00		November 2006 – March 2007
Period Total	95,000		$ 9.06(1)		$ 9.76	November 2006 – March 2007
Financial	37,500	$ 8.00				April – October 2007
Physical	40,000	$ 8.01				April – October 2007
Period Total	77,500		$ 8.00		$ 8.07	April – October 2007
Financial	30,000	$ 9.56				November 2007 – March 2008
Physical	40,000	$ 9.73				November 2007 – March 2008
Period Total	70,000		$ 9.66		$ 9.91	November 2007 – March 2008

(1) Average price calculated using fixed price and floor price for collars.

During the six months ended June 30, 2006, the Trust entered into certain physical contracts to purchase natural gas from a third party at fixed prices or price collars that were equivalent to or below the prices on existing physical contracts to sell natural gas to the same third party in order to effectively close out certain of its physical forward sales contracts at a premium. As a result of entering into these purchase contracts the Trust will collect a total of $4.0 million over the terms of the contracts, of which $3.4 million will be received from July to October, 2006 and $0.6 million will be received from November 2006 to March 2007. This amount has not been recorded in earnings for the current period nor has it been recorded as an asset on the Trust's balance sheet, but will contribute to future revenues as the offsetting contracts settle over their respective terms.

Financial results

Revenue

Revenue ($ thousands)	Three months ended June 30 **2006**	2005	Six months ended June 30 **2006**	2005
Natural gas revenue, before financial hedging (1)	**97,856**	100,328	**210,495**	176,275
Realized gains (losses) on financial instruments (2)	**3,724**	(94)	**1,460**	305
Total revenue	**101,580**	100,234	**211,955**	176,580

(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.

Natural gas revenue before financial hedging decreased two percent to $97.9 million for the three months ended June 30, 2006 compared to $100.3 million for the comparative period in 2005 as higher production levels related to the Northeast Alberta Acquisition and the acquisition of AcquireCo in February 2006 were offset by lower natural gas prices. Realized gains on financial forward contracts totaled $3.7 million for the period, as compared to realized losses of $0.1 million for the three months ended June 30, 2005. The Trust includes realized gains and losses on financial forward contracts in its calculation of realized natural gas prices, after hedging. Natural gas revenue before financial hedging increased to $210.5 million for the six months ended June 30, 2006 from $176.3 million for the first six months of 2005, primarily due to higher production levels.

The Trust recorded unrealized gains on financial instruments of $8.7 million and $15.9 million for the three and six months ended June 30, 2006 respectively reflecting the change in the fair value of financial forward contracts during the periods (see "Change in Accounting Policy" in this MD&A).

Cash flow

	Three months ended June 30				Six months ended June 30			
	2006		2005		**2006**		2005	
Cash flow reconciliation	**$ millions**	**$/Mcf**	$ millions	$/Mcf	**$ millions**	**$/Mcf**	$ millions	$/Mcf
Production (Bcf)		**14.8**		13.5		**28.5**		24.5
Revenue (1)	**101.6**	**6.85**	100.2	7.42	**211.9**	**7.45**	176.6	7.21
Royalties	**(16.2)**	**(1.09)**	(17.9)	(1.32)	**(38.0)**	**(1.34)**	(32.5)	(1.33)
Operating costs	**(19.4)**	**(1.31)**	(14.6)	(1.08)	**(42.2)**	**(1.48)**	(31.2)	(1.28)
Transportation costs	**(3.0)**	**(0.20)**	(3.3)	(0.25)	**(6.4)**	**(0.22)**	(6.3)	(0.26)
Operating netback from production (3)	**63.0**	**4.25**	64.4	4.77	**125.3**	**4.41**	106.6	4.34
Gas over bitumen royalty adjustments	**4.7**	**0.32**	10.3	0.77	**10.9**	**0.39**	15.1	0.62
Lease rentals	**(0.5)**	**(0.03)**	(0.5)	(0.04)	**(1.3)**	**(0.05)**	(1.6)	(0.06)
General and administrative (2)	**(5.3)**	**(0.35)**	(3.8)	(0.28)	**(8.3)**	**(0.29)**	(6.4)	(0.26)
Interest on bank and other debt	**(2.8)**	**(0.19)**	(2.1)	(0.16)	**(5.4)**	**(0.19)**	(3.8)	(0.15)
Interest on convertible debentures (2)	**(2.5)**	**(0.17)**	(1.8)	(0.13)	**(3.5)**	**(0.12)**	(2.4)	(0.10)
Capital taxes	**(0.0)**	**(0.00)**	(0.0)	(0.00)	**(0.0)**	**(0.00)**	(0.2)	(0.01)
Cash flow (2)(3)	**56.6**	**3.83**	66.5	4.93	**117.7**	**4.15**	107.3	4.38

(1) Revenue includes gains and losses on financial instruments.

(2) Excludes non-cash items.

(3) This is a non-GAAP measure; see "Significant accounting policies and non-GAAP measures" in this MD&A.

For the three months ended June 30, 2006, PET's average royalty rate (royalties as a percentage of revenues including gains and losses on financial instruments) was 15.9 percent compared to 17.8 percent for the same period in 2005. The lower royalty rate is due to PET's realized natural gas price being significantly higher than the Alberta Gas Reference Price for the current period. Alberta Crown royalties are based on the Alberta Gas Reference Price. The Trust's royalty rate measured 17.9 percent for the six months ended June 30, 2006 as compared to 18.4 percent for the first half of 2005.

Operating costs increased to $19.4 million ($1.31 per Mcf) in the three months ended June 30, 2006 from $14.6 million ($1.08 per Mcf) for the same period in 2005. Operating costs for the six months ended June 30, 2006 totaled $42.2 million or $1.48 per Mcf as compared to $31.2 million or $1.28 per Mcf for the first six months of 2005.

Unit-of-production costs increased 16 percent in 2006 due to fixed operating costs related to the operation of additional plants, additional maintenance and facility modifications required on the Northeast Alberta Acquisition assets and a general increase in the cost of field supplies and services. PET's operating costs are highest during the winter months when access to northeast Alberta properties dictates the timing of facility maintenance programs and the annual restocking of consumable field supplies. The Trust estimates operating costs on a unit-of-production basis of $1.30 to $1.40 per Mcf for 2006.

Transportation costs decreased 20 percent ($0.05 per Mcf) on a unit-of-production basis for the three month period ended June 30, 2006 as a result of the negotiation of natural gas sales contracts directly to end users proximal to the Trust's production in northeast Alberta, beginning in April 2006. These contracts benefit from reduced gas transportation costs.

Lower realized gas prices and increased operating costs offset somewhat by higher natural gas production volumes resulted in a $1.4 million decrease in PET's operating netback to $63.0 million for the three months ended June 30, 2006 from $64.4 million for the three months ended June 30, 2005.

Operating netback reconciliation ($ millions)

Production increase	$ 9.7
Price decrease, including realized gains on financial instruments	(8.4)
Royalty increase	1.7
Transportation cost decrease	0.3
Operating cost increase	(4.7)
Decrease in net operating income	$ (1.4)

General and administrative expenses were $6.0 million for the three months ended June 30, 2006 compared to $4.3 million for the three months ended June 30, 2005. The increase is due in part to severance costs for AcquireCo employees and fees related to Sarbanes Oxley initiatives. The Trust's general and administrative expenses are typically highest in the second quarter of the year as annual bonuses for the prior year are paid during that period. For the six months ended June 30, 2006 general and administrative expenses totaled $9.3 million, an increase of $2.1 million over the comparative period for 2005. The scale of PET's operations increased significantly with the Northeast Alberta and AcquireCo acquisitions completed in 2005 and early 2006 and as a result general and administrative expenses have increased. The Trust has also increased staffing levels to facilitate planning and execution of our increased capital spending plans. Cash general and administrative expenses on a unit-of-production basis were $0.35 per Mcf for the three months ended June 30, 2006 as compared to $0.28 per Mcf in 2005.

Interest on bank and other debt totaled $2.8 million for the three months ended June 30, 2006 as compared to $2.1 million for the comparable period in 2005. Interest expense has increased primarily as a result of slightly higher debt levels and higher short-term interest rates in the second quarter of 2006 as compared to 2005.

Interest on convertible debentures for the three months ended June 30, 2006 increased by $1.0 million compared to the three months ended June 30, 2005 due primarily to the issuance of $100 million of 6.25% convertible unsecured subordinated debentures (the "2006 6.25% Debentures") in April 2006, offset somewhat by the conversion of $26.2 million of the Trust's 8% convertible unsecured subordinated debentures (the "8% Debentures") and $44.7 million of the Trust's 6.25% convertible unsecured subordinated debentures issued in April 2005 (the "2005 6.25% Debentures") from July 1, 2005 to June 30, 2006.

On October 4, 2004 the Government of Alberta enacted amendments to the royalty regulation with respect to natural gas (the "Royalty Regulation"), which provide a mechanism whereby the Government may prescribe additional royalty components to effect a reduction in the royalty calculated through the Crown royalty system for operators of gas wells which have been denied the right to produce by the AEUB as a result of recent bitumen conservation decisions. The Department of Energy issued an Information Letter 2004-36 ("IL 2004-36") which, in conjunction with the Royalty Regulation, sets out the details of the gas over bitumen financial solution. 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 21.5 MMcf/d in the second quarter of 2006. Deemed production represents all PET natural gas production shut-in or denied production pursuant to a decision report, corresponding order or general bulletin of the AEUB, or through correspondence in relation to an AEUB ID 99-1 application. In accordance with IL 2004-36, the deemed production volume related to wells shut-in is reduced by 10 percent at the end of every year of shut-in. PET's deemed production dropped on July 1, 2006 to approximately 20 MMcf/d.

For the three months ended June 30, 2006 the Trust received $4.7 million in gas over bitumen royalty adjustments as compared to $10.3 million received in the second quarter of 2005. In the 2005 period PET received $4.8 million in retroactive royalty adjustments related to prior periods. These amounts 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. This brings cumulative royalty adjustments received to June 30, 2006 to $52.7 million. 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, royalty adjustments are recorded as a component of cash flow and are considered distributable income.

In the second quarter of 2006, PET disposed of certain shut-in gas wells in the gas over bitumen area. As part of the disposition agreement, the Trust continues to receive the gas over bitumen royalty adjustments related to the sold wells, although the ownership of the natural gas reserves is transferred to the buyer. As such, any overriding royalty payable to the Crown when gas production recommences from the affected wells is no longer PET's responsibility. 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. The Trust reclassifed $13.7 million from the gas over bitumen liability on the balance sheet into revenues representing all royalty adjustments received to date in respect of the disposed wells. In future periods, royalty adjustments received in respect of these wells will be recorded directly to revenue.

As a result of the variables discussed above, cash flow netbacks decreased 22 percent from $4.93 per Mcf in the second quarter of 2005 to $3.83 per Mcf in the second quarter of 2006. Despite the ten percent increase in production volumes, cash flow decreased by 15 percent to $56.6 million ($0.68 per Trust Unit) for the three months ended June 30, 2006 from $66.5 million ($0.90 per Trust Unit) in the 2005 period. Cash flow for the six months ended June 30, 2006 totaled $117.7 million ($1.41 per Trust Unit) as compared to $107.3 million ($1.54 per Trust Unit) for the comparative period in 2005. The ten percent increase from 2005 was primarily due to higher production volumes and slightly higher realized natural gas prices for the six month period.

Earnings

The Trust reported net earnings of $21.8 million ($0.26 per basic and diluted Trust Unit) for the three months ended June 30, 2006 as compared to $11.4 million ($0.16 per basic Trust Unit, $0.15 per diluted Trust Unit) for the 2005 period. The increase from 2005 is primarily a result of higher natural gas production volumes, the reclassification of $13.7 million in royalty adjustments to revenue, a timing difference in booking exploration expenses in the second quarter of 2006 and $8.7 million in unrealized gains on financial instruments recorded as a result of the change in accounting policy regarding natural gas financial forward contracts (see "Change in Accounting Policy" in this MD&A), offset somewhat by lower operating netbacks and higher DD&A expense. Net earnings for the six months ended June 30, 2006 rose to $29.8 million ($0.36 per basic Trust Unit, $0.35 per diluted Trust Unit) from $13.6 million ($0.20 per basic Trust Unit, $0.19 per diluted Trust Unit) in 2005.

Exploration expenses decreased to $1.1 million for the three months ended June 30, 2006 from $10.1 million for the second quarter of 2005 primarily due to the timing of seismic programs in 2006 as compared to 2005. In 2006 seismic programs totaling $7.6 million in northeast Alberta were substantially completed and expensed in the first quarter. By contrast, the 2005 winter seismic programs were not completed until April and therefore were not expensed until the second quarter of 2005.

Depletion, depreciation and accretion ("DD&A") expense increased from $34.4 million in the second quarter of 2005 to $50.6 million in 2006 due to increased production volumes and an increase in the Trust's depletion rate. PET's depletion rate was $3.43 per Mcf in the three months ended June 30, 2006 as compared to $2.54 per Mcf in 2005. DD&A expense for the six months ended June 30, 2006 totaled $95.9 million ($3.38 per Mcf), an increase of $26.5 million over the $69.4 million ($2.83 per Mcf) recorded in the first six months of 2005.

Summary of quarterly results

				Three months ended
($ thousands except prices and per Trust Unit amounts)	June 30, 2006	Mar 31, 2006	Dec 31, 2005	Sept 30, 2005
Natural gas revenues before royalties (1)	$ 97,856	$ 112,639	$ 129,233	$ 118,928
Cash flow (2)	$ 56,605	$ 61,112	$ 78,200	$ 74,726
Per Trust Unit - basic	$ 0.68	$ 0.74	$ 0.96	$ 0.95
Net earnings	$ 21,816	$ 7,969	$ 17,899	$ 30,339
Per Trust Unit - basic	$ 0.26	$ 0.10	$ 0.22	$ 0.39
- diluted	$ 0.26	$ 0.10	$ 0.22	$ 0.38
Average AECO daily index price ($/GJ)	$ 5.71	$ 7.13	$ 10.72	$ 8.89

				Three months ended
($ thousands except prices and per Trust Unit amounts)	June 30, 2005	Mar 31, 2005	Dec 31, 2004	Sept 30, 2004
Natural gas revenues before royalties (1)	$ 100,328	$ 75,947	$ 79,665	$ 59,156
Cash flow (2)	$ 66,491	$ 40,801	$ 56,521	$ 31,301
Per Trust Unit - basic	$ 0.90	$ 0.62	$ 0.87	$ 0.52
Net earnings (loss)	$ 11,433	$ 2,199	$ (29,696)	$ 4,813
Per Trust Unit - basic	$ 0.16	$ 0.03	$ (0.46)	$ 0.08
- diluted	$ 0.15	$ 0.03	$ (0.46)	$ 0.08
Average AECO daily index price ($/GJ)	$ 6.99	$ 6.53	$ 6.17	$ 5.89

(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.

Natural gas revenues and cash flow trended steadily higher through 2004 and 2005 as a result of increasing production due primarily to acquisition activity and higher natural gas prices. In 2006 natural gas prices declined significantly from the levels experienced in late 2005 and revenues and cash flows decreased accordingly.

The increased net earnings in the third and fourth quarters of 2005 compared to previous quarters are due to higher natural gas revenues, offset somewhat by higher royalties and DD&A expenses as compared to prior quarters. Earnings have remained strong in 2006 despite lower cash flows as a result of unrealized gains on financial instruments and the reclassification of certain gas over bitumen royalty adjustments into earnings. The net loss in the fourth quarter of 2004 was a result of an after-tax write-down of property and equipment of $39 million pertaining primarily to PET's Saskatchewan properties.

Liquidity and capital resources

Net debt ($ thousands except per Trust Unit and percent amounts)	**June 30, 2006**	December 31, 2005
Bank and other debt	**221,366**	168,106
Convertible debentures	**157,572**	64,888
Working capital deficiency (surplus) (2)	**9,844**	(1,131)
Net debt	**388,782**	231,863
Trust Units outstanding (thousands)	**83,857**	82,482
Market price at end of period ($/Trust Unit)	**18.50**	22.17
Market value of Trust Units	**1,551,355**	1,828,626
Total market capitalization (1)	**1,940,137**	2,060,489
Net debt as a percentage of total capitalization (%)	**20.0**	11.3
Cash flow for the period (1)	**56,605**	260,218
Annualized cash flow (1)	**226,420**	260,218
Net debt to annualized cash flow ratio (times) (1)	**1.7**	0.9

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

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

PET has a demand credit facility with a syndicate of Canadian chartered banks. The revolving feature of the facility expires on May 29, 2007 if not extended. Pursuant to the terms of the credit agreement, the Trust expects to request that the facility be extended for 364 days and anticipates that this request will be granted. The Trust's lenders reconfirmed the borrowing base under its credit facility at $310 million for a further six months as at March 31, 2006. The facility consists of a demand loan of $300 million and a working capital facility of $10 million. 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 increased to $221.4 million at June 30, 2006, as compared to $168.1 million at December 31, 2005 as a result of expenditures related to the Trust's capital programs, primarily incurred in the first quarter of 2006. In addition to amounts outstanding under the credit facility PET has outstanding letters of credit in the amount of $3.9 million.

At June 30, 2006 PET had 2006 6.25% Debentures, 2005 6.25% Debentures and 8% Debentures outstanding as follows:

Convertible debentures series	2006 – 6.25%	2005 – 6.25%	8%
Principal outstanding ($millions)	100.0	55.3	6.5
Maturity date	April 30, 2011	Sept. 30, 2009	June 30, 2010
Conversion price ($ per Trust Unit)	23.80	19.35	14.20
Fair market value ($millions)	100.8	56.5	8.6

Fair values of debentures are calculated by multiplying the number of debentures outstanding at June 30, 2006 by the quoted market price per debenture at that date. During the second quarter $0.2 million of the 2005 6.25% Debentures and $0.6 million of the 8% Debentures were converted into 53,000 Trust Units.

Net debt to annualized cash flow rose to 1.7 times for the quarter ended June 30, 2006 from 0.9 times for the year ended December 31, 2005. The increase in net debt is largely a function of the acquisition of AcquireCo in February 2006 and the Trust's significant winter capital program. Approximately 80 to 85 percent of the Trust's annual exploration and development expenditures are typically incurred in the first half of the year.

Cumulative distributions for the second quarter of 2006 totaled $0.72 per Trust Unit consisting of $ 0.24 per Trust Unit paid on May 15, June 15 and July 17. The Trust's payout ratio, which is the ratio of distributions to cash flow, was 106.5 percent in the current quarter as compared to 72.6 percent for the second quarter of 2005. As a result of continued weakness in natural gas prices, PET reduced its monthly distribution to $0.20 per Trust Unit effective with the July distribution paid on August 15, 2006. The payout ratio in future periods will largely be determined by natural gas prices and production levels.

On April 6, 2006 PET issued $100 million in 6.25% convertible unsecured subordinated debentures for net proceeds of $95.7 million. The 2006 6.25% Debentures pay interest semi-annually on April 30 and October 31 with the initial interest payment due on October 31, 2006. The proceeds of the issuance were initially used to repay bank debt which had increased $92 million with the AcquireCo acquisition, and will subsequently be used for general corporate and working capital purposes.

Through the Trust's Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan") $6.0 million was invested by Unitholders during the three months ended June 30, 2006 and a total of 333,000 Trust Units were issued at an average price of $18.00 per Trust Unit. For the six months ended June 30, 2006 $17.2 million was invested in the DRIP plan and 918,000 Trust Units were issued.

PET anticipates that distributions and capital expenditures for the remainder of 2006 will be funded by cash flow with any excess cash flow and proceeds from the DRIP Plan being applied to reduce bank and other debt.

2006 Outlook and sensitivities

The Trust's current hedging and physical forward sales portfolio has significantly reduced PET's exposure to downside in natural gas prices. The following table reflects PET's projected realized gas price, monthly cash flow and payout ratio at the current monthly distribution of $0.20 per Trust Unit, for the remaining six months of 2006 at certain AECO natural gas price levels and incorporating all of the Trust's current financial hedges and physical forward sales contracts.

	Average AECO Monthly Index Gas Price July to December 2006 ($/GJ)		
Cash flow sensitivity analysis	$5.00	$6.00	$7.00
Natural gas production (MMcf/d)	152	152	152
Realized gas price (1) ($/Mcf)	6.83	7.38	7.94
Cash flow (2) ($million/month)	19.5	21.5	23.6
Per Trust Unit ($/Unit/month)	0.231	0.255	0.280
Payout ratio (2) (%)	86	78	71
Ending total net debt ($million)	398	387	374
Ending total net debt to cash flow ratio (3) (times)	1.7	1.6	1.4

(1) PET's weighted average forward price on an average of 86,700 GJ/d for the period from July 1 to December 31, 2006 is $7.90/GJ using fixed prices and floor prices for collars.

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

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

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 and abandoned wells are expensed rather than capitalized in the year incurred. However, to make reported cash 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.

Cash flow

Management uses funds flow from operations before changes in non-cash working capital ("cash flow"), cash flow per Trust Unit and annualized cash flow to analyze operating performance and leverage. Cash 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. Cash flow as presented is not intended to represent operating cash flow or operating profits for the period nor should it be viewed as an alternative to cash flow provided by operating activities, net earnings or other measures of financial performance calculated in accordance with GAAP. Cash flow is reconciled to its closest GAAP measure, cash flow provided by operating activities, as follows:

Cash flow GAAP reconciliation	Three months ended June 30		Six months ended June 30	
($ thousands except per Trust Unit amounts)	**2006**	2005	**2006**	2005
Cash flow provided by operating activities	**46,614**	45,945	**116,694**	86,905
Exploration costs (1)	**591**	9,608	**8,926**	9,608
Expenditures on asset retirement obligations	**1,915**	–	**2,453**	–
Changes in non-cash operating working capital	**7,485**	10,938	**(10,356)**	10,779
Cash flow	**56,605**	66,491	**117,717**	107,292
Cash flow per Trust Unit (2)	**$ 0.68**	$ 0.90	**$ 1.41**	$ 1.54

(1) Certain exploration costs are added back to cash 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 cash 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.

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

Payout ratio

Payout ratio refers to distributions measured as a percentage of cash flow for the period and is used by management to analyze cash flow available for development and acquisition opportunities as well as overall sustainability of distributions. Cash 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 cash flow netbacks

Operating and cash flow netbacks are used by management to analyze margin and cash flow on each Mcf of natural gas production. Operating and cash 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 cash flow netbacks should not be viewed as an alternative to cash flow from operations, net earnings per Trust Unit or other measures of financial performance calculated in accordance with GAAP.

Unitholders' equity before distributions and cumulative distributions since inception

Unitholders' equity before distributions and cumulative distributions since inception are used by management to compare total equity before any reduction for distributions from period to period. Unitholders' equity before distributions and cumulative distributions since inception 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. Unitholders' equity before distributions and cumulative distributions since inception should not be viewed as alternatives to Unitholders' equity or other measures 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 Canadian GAAP and therefore it may not be comparable with the calculation of similar measures for other entities. Total capitalization is not intended to represent the total funds from equity and debt received by the Trust.

Revenue, including realized gains (losses) on financial instruments

Revenue, including realized gains (losses) on financial instruments is used by management to calculate the Trust's net realized natural gas price taking into account monthly settlements on financial forward natural gas sales and foreign exchange contracts. These contracts are put in place to protect PET's cash 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

Change in accounting policy

Effective January 1, 2006 PET prospectively applied mark-to-market accounting for all financial forward natural gas contracts. The Trust formerly accounted for financial forward natural gas contracts using hedge accounting as described in CICA Accounting Guideline 13 – Hedging Relationships. Accordingly, the fair values of these financial instruments as at January 1, 2006 were recorded on the Trust's balance sheet and are amortized into earnings over the contractual life of the associated instrument. Changes in fair value of these financial instruments from January 1, 2006 to June 30, 2006, as well as changes in fair values of other financial forward natural gas and foreign exchange contracts as at June 30, were included in net earnings for the six month period. The combination of the change in fair value during the six month period ended June 30, 2006 and amortization of the fair values recorded at January 1, 2006 was an unrealized gain on financial instruments of $15.9 million (three months ended June 30, 2006 – unrealized gain of $8.7 million). Tabular reconciliations of unrealized gains on financial instruments recorded in the statement of earnings and related balance sheet amounts are included in Note 11 to the consolidated financial statements as at and for the three and six months ended June 30, 2006.

As the change in accounting policy was applied prospectively there is no related impact on earnings for periods related to 2005 and earlier.

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, judgements 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.

The critical accounting estimates employed by PET in the preparation of its consolidated financial statements are substantially unchanged from those presented in the MD&A for the year ended December 31, 2005.

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.

Gas over bitumen issue

On January 24, 2006, the AEUB invited members in industry to a meeting to discuss its intent to commence a process with respect to bitumen conservation policies in the Cold Lake and Peace River Oil Sands Areas of Alberta. PET has current production of approximately 5.8 MMcf/d from the Bluesky-Gething formations in the portions of the Panny and Darwin fields which are located within the Peace River Oil Sands Area. Industry comment was solicited prior to February 14, 2006. On June 9, 2006, the AEUB announced that it will hold a hearing commencing October 31, 2006 to hear two applications concerning the Clearwater formation in the Cold Lake Area. PET has no production that will be directly affected by the upcoming hearing in Cold Lake. At this time, the EUB will not proceed with a hearing concerning the Peace River Oil Sands Area. Gas production from these zones may be identified in the future as posing a potential concern with respect to communication with potentially recoverable bitumen resources. The Government of Alberta has not made comment as to whether the Gas over Bitumen Royalty Adjustment applied to shut-in gas in the Wabiskaw-McMurray in the Athabasca Oil Sands Area would apply to other regions.

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

Other risks and uncertainties affecting PET's operations are substantially unchanged from those presented in the MD&A for the year ended December 31, 2005.

Forward-looking information

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

The use of any of the words "anticipate", "continue", "estimate", "expect", "may", "will", "project", "should", "believe", "outlook" and similar expressions are intended to identify forward-looking statements. These statements involve known and unknown risks, uncertainties and other factors that may cause actual results or events to differ materially from those anticipated in our forward-looking statements. We believe the expectations reflected in these forward-looking statements are reasonable. However, we cannot assure the reader that these expectations will prove to be correct. The reader should not unduly rely on forward-looking statements included in this report. These statements speak only as of the date of the MD&A.

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

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

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

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

The above list of risk factors is not exhaustive.

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	June 30, 2006	December 31, 2005
($ thousands)	(unaudited)	
Assets		
Current assets		
Accounts receivable	**$ 38,290**	$ 57,837
Financial instruments (notes 2 and 11)	**15,571**	–
	53,861	57,837
Property, plant and equipment (notes 4 and 5)	**804,130**	728,173
Goodwill	**29,129**	29,129
Other assets (note 3)	**9,123**	5,269
Financial instruments (notes 2 and 11)	**368**	–
	$ 896,611	$ 820,408
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 28,007**	$ 36,910
Distributions payable	**20,126**	19,796
Bank and other debt (note 6)	**221,366**	168,106
	269,499	224,812
Gas over bitumen royalty adjustments (note 13)	**39,058**	41,789
Asset retirement obligations (note 10)	**99,892**	94,276
Convertible debentures (note 7)	**157,572**	64,888
Unitholders' equity		
Unitholders' capital (note 8)	**791,650**	769,210
Equity component of convertible debentures (note 7)	**4,527**	490
Contributed surplus (note 9)	**3,975**	4,052
Deficit	**(469,562)**	(379,109)
	330,590	394,643
	$ 896,611	$ 820,408

See accompanying notes
Basis of presentation: note 1
Commitments: notes 11 and 12
Contingencies: note 13

John W. Peltier
Director

Donald J. Nelson
Director

Interim Consolidated Statements of Earnings and Deficit

(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	**2006**	2005
($ thousands except per Unit amounts, unaudited)				
Revenue				
Natural gas	**$ 97,856**	$ 100,328	**$ 210,495**	$ 176,275
Royalties	**(16,157)**	(17,861)	**(38,031)**	(32,500)
Realized gain/(loss) on financial instruments (notes 2 and 11)	**3,724**	(94)	**1,460**	305
Unrealized gain on financial instruments (notes 2 and 11)	**8,730**	-	**15,939**	-
Gas over bitumen revenue (note 13)	**13,677**	-	**13,677**	-
	107,830	82,373	**203,540**	144,080
Expenses				
Operating	**19,424**	14,639	**42,171**	31,243
Transportation costs	**3,023**	3,312	**6,402**	6,290
Exploration expenses	**1,056**	10,136	**10,242**	11,182
General and administrative (note 9)	**5,972**	4,302	**9,313**	7,248
Interest	**2,835**	2,138	**5,482**	3,776
Interest on convertible debentures	**3,037**	2,011	**4,201**	2,678
Depletion, depreciation and accretion	**50,621**	34,372	**95,915**	69,366
	85,968	70,910	**173,726**	131,783
Earnings before income taxes	**21,862**	11,463	**29,814**	12,297
Future income tax reduction	**-**	-	**-**	1,519
Capital taxes	**(46)**	(30)	**(29)**	(184)
	(46)	(30)	**(29)**	1,335
Net earnings	**21,816**	11,433	**29,785**	13,632
Deficit, beginning of period	**(431,094)**	(261,179)	**(379,109)**	(219,776)
Distributions paid or payable	**(60,284)**	(48,302)	**(120,238)**	(91,904)
Deficit, end of period	**$ (469,562)**	$ (298,048)	**$ (469,562)**	$ (298,048)
Earnings per Trust Unit (note 8(c))				
Basic	**$ 0.26**	$ 0.16	**$ 0.36**	$ 0.20
Diluted	**$ 0.26**	$ 0.15	**$ 0.35**	$ 0.19
Distributions per Trust Unit	**$ 0.72**	$ 0.66	**$ 1.44**	$ 1.32

See accompanying notes

Interim Consolidated Statements of Cash Flows

(Unaudited)

	Three Months Ended June 30		Six Months Ended June 30	
	2006	2005	**2006**	2005
($ thousands, unaudited)				
Cash provided by (used for)				
Operating activities				
Net earnings	**$ 21,816**	$ 11,433	**$ 29,785**	$ 13,632
Items not involving cash				
Depletion, depreciation and accretion	**50,621**	34,372	**95,915**	69,366
Trust Unit-based compensation	**716**	512	**1,052**	880
Future income tax reduction	**-**	-	**-**	(1,519)
Unrealized gain on financial instruments	**(8,730)**	-	**(15,939)**	-
Amortization of other assets	**553**	219	**709**	219
Gas over bitumen royalty adjustments	**4,715**	10,347	**10,946**	15,106
Gas over bitumen revenue	**(13,677)**	-	**(13,677)**	-
Expenditures on asset retirement obligations	**(1,915)**	-	**(2,453)**	-
Change in non-cash working capital	**(7,485)**	(10,938)	**10,356**	(10,779)
Cash flow provided by operating activities	**46,614**	45,945	**116,694**	86,905
Financing activities				
Issue of Trust Units	**1,915**	154,253	**8,860**	156,787
Distributions to Unitholders	**(56,196)**	(37,630)	**(111,784)**	(78,547)
Issue of convertible debentures	**95,631**	96,000	**95,631**	96,000
Change in bank and other debt	**(60,914)**	16,567	**53,260**	58,935
Change in non-cash working capital	**500**	2,764	**1,316**	3,157
	(19,064)	231,954	**47,283**	236,332
	$ 27,550	$ 277,899	**$ 163,977**	$ 323,237
Investing activities				
Acquisition of investments	**-**	-	**-**	(1,243)
Acquisition of properties and corporate assets	**(1,283)**	(257,960)	**(92,275)**	(284,908)
Exploration and development expenditures	**(9,875)**	5,224	**(81,841)**	(35,004)
Proceeds on sale of property and equipment	**12,737**	1,036	**14,207**	1,036
Change in non-cash working capital	**(29,129)**	(26,199)	**(4,068)**	(3,118)
	$ (27,550)	$ (277,899)	**$ (163,977)**	$ (323,237)
Change in cash	**-**	-	**-**	-
Cash, beginning of period	**-**	-	**-**	-
Cash, end of period	**$ -**	$ -	**$ -**	$ -
Interest paid	**$ 4,791**	$ 3,164	**$ 7,885**	$ 6,935
Taxes paid	**-**	$ 71	**$ 125**	$ 105

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, 2005, except as described in note 2 below. The 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 26 through 27 of the Trust's 2005 annual report and should be read in conjunction with these interim financial statements.

2. Change in accounting policy

Effective January 1, 2006 PET prospectively applied mark-to-market accounting for all financial forward natural gas contracts. The Trust previously accounted for financial forward natural gas contracts using hedge accounting. Accordingly, the fair values of these financial instruments as at January 1, 2006 were recorded on the Trust's balance sheet and are amortized into earnings over the contractual life of the associated instrument. Changes in fair value of these financial instruments from January 1, 2006 to June 30, 2006, as well as fair values of other financial forward natural gas contracts as at June 30, 2006 are recorded to earnings.

The impact on the Trust's consolidated financial statements at January 1, 2006 resulted in the recognition of financial instrument liabilities with a fair value of $20.5 million and a deferred loss of $20.5 million which will be recognized into net earnings over the life of the related contracts. At June 30, 2006 $15.9 million of the initial deferred loss has been amortized into net earnings (see note 11).

3. Other assets

	June 30, 2006	December 31, 2005
Convertible debenture issue costs	**$ 6,123**	$ 2,269
Investment	**3,000**	3,000
	$ 9,123	$ 5,269

Convertible debenture issue costs are amortized to earnings over the life of the related debentures and any unamortized amounts are reclassified to Unitholders' capital as and when debentures are converted to Trust Units. For the three and six month periods ended June 30, 2006, amortization of $0.2 and $0.5 million respectively (2005 – nil and $0.2 million) has been recognized in these consolidated financial statements. During the three months ended June 30, 2006 the Trust assumed $4.4 million in convertible debenture issue costs associated with the issuance of the 2006 6.25% Convertible Debentures (see note 7).

The investment of $3.0 million is related to PET's 11% interest in Sebring Energy Inc. ("Sebring"), a privately held oil and gas company. PET exchanged certain oil and gas assets for 4.0 million shares in Sebring in January 2005. This investment is accounted for on a cost basis.

4. Property, plant and equipment

	June 30, 2006	December 31, 2005
Petroleum and natural gas properties	**$ 1,437,920**	$ 1,274,639
Asset retirement costs	**92,615**	87,990
Corporate assets	**16,542**	16,020
	1,547,077	1,378,649
Accumulated depletion and depreciation	**(742,947)**	(650,476)
	$ 804,130	$ 728,173

Property, plant and equipment costs at June 30, 2006 included $91.9 million (June 30, 2005 - $88.4 million) currently not subject to depletion.

5. Corporate acquisition

On February 16, 2006 PET acquired a private Alberta company ("AcquireCo") for consideration of $91.3 million in cash funded through the Trust's existing credit facility. The following table summarizes the estimated fair value of the assets acquired and liabilities assumed at the date of acquisition. The Trust has not yet completed its final evaluation of the assets acquired and the liabilities assumed. Therefore, the purchase price and the allocation of such to the acquired assets and liabilities is subject to change.

Property, plant and equipment	$ 93,633
Land	2,800
Working capital deficiency	(4,465)
Cash	551
Asset retirement obligation	(1,213)
Cash consideration paid	$ 91,306

6. Bank and other debt

PET has a revolving credit facility with a syndicate of Canadian Chartered Banks ("Credit Facility"). The Credit Facility currently has a borrowing base of $310 million, consisting of a demand loan of $300 million and a working capital facility of $10 million. In addition to amounts outstanding under the Credit Facility, PET has outstanding letters of credit in the amount of $3.87 million. 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 Credit Facility.

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 June 30, 2006 was 5.19%.

7. Convertible debentures

In accordance with Canadian accounting standards, the Trust's convertible debentures are classified as debt with a portion of the proceeds allocated to equity representing the value of the conversion feature. As the debentures are converted, a portion of debt and equity amounts are transferred to Unitholders' capital. The debt balance associated with the convertible debentures accretes over time to the amount owing on maturity and such increases in the debt balance are reflected as non-cash interest expense in the statement of earnings.

The 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. During the six month period ended June 30, 2006, $2.6 million of 2005 6.25% Convertible Debentures were converted resulting in the issuance of 136,170 Trust Units.

The Trust's 8% convertible unsecured subordinated debentures ("8% Convertible Debentures") mature on September 30, 2009, bear interest at 8.0% per annum paid semi-annually on March 31 and September 30 of each year and are subordinated to substantially all other liabilities of PET including the Credit Facility. The 8% Convertible Debentures are convertible at the option of the holder into Trust Units at any time prior to the maturity date at a conversion price of $14.20 per Trust Unit. During the six month period ended June 30, 2006, $0.9 million of 8% Convertible Debentures were converted, resulting in the issuance of 62,385 Trust Units.

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% of the weighted average trading price for 10 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.

At June 30, 2006, the Trust had $6.5 million in 8% Convertible Debentures outstanding with a fair market value of $8.6 million, $55.3 million in 2005 6.25% Convertible Debentures outstanding with a fair market value of $56.5 million, and $100.0 million in 2006 6.25% Convertible Debentures outstanding with a fair market value of $100.8 million.

	8% Series		2005 6.25% Series		2006 6.25% Series		
	Number of debentures	Amount	Number of debentures	Amount	Number of debentures	Amount	Total Amount
Balance, December 31, 2004	38,419	$ 38,419	-	$ -	-	$ -	$ 38,419
April 26, 2005 issuance	-	-	100,000	100,000	-	-	100,000
Portion allocated to equity	-	-	-	(846)	-	-	(846)
Accretion of non-cash interest expense	-	-	-	118	-	-	118
Converted into Trust Units	(31,065)	(31,065)	(42,094)	(41,738)	-	-	(72,803)
Balance, December 31, 2005	7,354	7,354	57,906	57,534	-	-	64,888
April 6, 2006 issuance	-	-	-	-	100,000	100,000	100,000
Portion allocated to equity	-	-	-	-	-	(4,059)	(4,059)
Accretion of non-cash interest expense	-	-	-	58	-	183	241
Converted into Trust Units	(886)	(886)	(2,635)	(2,612)	-	-	(3,498)
Balance, June 30, 2006	**6,468**	**$ 6,468**	**55,271**	**$ 54,980**	**100,000**	**$ 96,124**	**$ 157,572**

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

Balance, as at December 31, 2005	$ 490
Conversion of Trust Units	(22)
Equity component of 2006 6.25% Convertible Debentures	4,059
Balance, as at June 30, 2006	**$ 4,527**

8. 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, 2004	65,326,971	$ 495,862
Units issued pursuant to Unit offering	9,500,000	160,075
Units issued pursuant to Unit Incentive Plan	438,250	4,013
Units issued pursuant to Distribution Reinvestment Plan	2,853,601	49,471
Units issued pursuant to conversion of debentures	4,363,022	73,158
Issue costs on convertible debentures converted to Trust Units	-	(2,685)
Trust Unit issue costs	-	(10,684)
Balance, December 31, 2005	82,481,844	769,210
Units issued pursuant to Unit Incentive Plan	254,750	1,794
Units issued pursuant to Bonus Rights Plan	3,572	68
Units issued pursuant to Distribution Reinvestment Plan	918,230	17,174
Units issued pursuant to conversion of debentures	198,555	3,521
Issue costs on convertible debentures converted to Trust Units	-	(117)
Balance, June 30, 2006	**83,856,951**	**$ 791,650**

c) Per Unit information

Basic earnings per Trust Unit are calculated using the weighted average number of Trust Units outstanding during the three months and six months ended June 30, 2006 of 83,662,645 and 83,386,928 (2005 - 73,558,001 and 69,716,530 respectively). PET uses the treasury stock method where only dilutive instruments where market price exceeds exercise price impact the diluted calculations. In computing diluted earnings per Trust Unit for the three and six month periods ended June 30, 2006, 608,849 and 716,182 net Trust Units respectively were added to the weighted average number of Trust Units outstanding (2005 –553,036 and 545,657 net Trust Units) for the dilutive effect of Incentive Rights. In computing diluted earnings per Trust Unit for the three and six month periods ended June 30, 2006 367,500 and 235,000 Incentive Rights respectively were excluded as the exercise prices exceeded the average market price for the three and six month periods ended June 30, 2006 (2005 – 239,500 and 239,500 respectively).

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 10 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.

9. Incentive plans

a) Unit incentive plan

PET has adopted a unit incentive plan ("Unit Incentive Plan") which permits the Administrator's Board of Directors to grant non transferable rights to purchase Trust Units ("Incentive Rights") to its and affiliated entities' employees, officers, directors and other direct and indirect service providers. The calculated fair values of the Incentive Rights are amortized to net earnings over the vesting period of the Incentive Rights. The Trust recorded Trust Unit-based compensation of $0.5 and $0.9 million respectively for the three and six month periods ended June 30, 2006 ($0.6 and $1.0 million respectively for the three and six month periods ended June 30, 2005). The Incentive Rights are only dilutive to the calculation of earnings per Trust Unit if the exercise price is below the fair value of the Trust Units.

At June 30, 2006 a combined total of ten percent of total Trust Units outstanding had been reserved under the Unit Incentive Plan and the Bonus Rights Plan (see note 9 (b)). As at June 30, 2006 143,406 Incentive Rights granted under the Unit Incentive Plan had vested but were unexercised (12,500 as of June 30, 2005).

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	
	2006	2005
Distribution yield (%)	**3.1 – 3.8**	1.7 – 3.7
Expected volatility (%)	**21.5 – 22.5**	21.0
Risk-free interest rate (%)	**3.85 – 4.28**	3.12 – 3.89
Expected life of Incentive Rights (years)	**3.75 – 4.5**	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	**$ 3.16**	$ 2.91

Incentive Rights	Average exercise price	Incentive Rights
Balance, December 31, 2004	$ 6.13	1,612,750
Granted	17.33	722,125
Exercised	3.50	(438,250)
Cancelled	12.37	(248,500)
Balance, December 31, 2005	$ 10.79	1,648,125
Granted	18.72	562,250
Exercised	0.55	(254,750)
Cancelled	12.23	(68,125)
Balance, June 30, 2006	**$ 14.48**	**1,887,500**

The following summarizes information about Incentive Rights outstanding at June 30, 2006 assuming the reduced exercise price described above:

Range of exercise prices	Number outstanding at June 30, 2006	Weighted average contractual life (years)	Weighted average exercise price/ Incentive Right	Number exercisable at March 31, 2006	Weighted average exercise price/ Incentive Right
$0.001	232,000	1.6	$ 0.001	-	-
$6.60 - $6.72	135,000	2.4	6.66	37,500	$ 6.65
$7.41 - $12.37	329,000	3.3	8.17	2,500	8.34
$13.43 - $17.50	454,250	3.8	15.12	8,250	15.03
$17.89 - $21.76	737,250	4.5	19.08	-	-
Total	**1,887,500**	**3.6**	**$ 14.48**	**48,250**	**$ 12.03**

A reconciliation of contributed surplus is provided below:

Balance, as at December 31, 2004	$ 4,536
Trust Unit-based compensation expense	1,993
Transfer to Unitholders' capital on exercise of Incentive Rights	(2,477)
Balance, as at December 31, 2005	4,052
Bonus Rights adjustment	592
Trust Unit-based compensation expense	1,052
Transfer to Unitholders' capital on exercise of Incentive Rights	(1,721)
Balance, as at June 30, 2006	**$ 3,975**

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 six month periods ended June 30, 2006 $0.2 million in compensation expense was recorded in respect of the Bonus Rights granted (three and six month periods ended June 30, 2005-nil). During the three month period ended June 30, 2006 a total of 30,666 Bonus Rights were granted, 24,683 were vested, and 3,572 were exercised.

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

	Bonus Rights
Balance, December 31, 2004	-
Granted	25,478
Cancelled	(1,226)
Additional Grants for Accrued Distributions	2,457
Balance, December 31, 2005	26,709
Granted	30,666
Exercised	(3,572)
Additional Grants for Accrued Distributions	3,010
Balance, June 30, 2006	**56,813**

10. 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 $99.9 million as at June 30, 2006 based on an undiscounted total future liability of $200.3 million. These payments are expected to be made over the next 25 years with the majority of costs incurred between 2010 and 2015. PET used a credit adjusted risk free rate of 7.1% to calculate the present value of the asset retirement obligation.

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

	June 30, 2006	December 31, 2005
Obligation, beginning of period	**$ 94,276**	$ 34,116
Obligations incurred	**3,412**	8,232
Obligations acquired	**1,213**	13,267
Revisions to estimates	**-**	35,704
Expenditures for obligations during the period	**(2,453)**	(660)
Accretion expense	**3,444**	3,617
	$ 99,892	$ 94,276

11. Financial instruments

As disclosed in note 2, on January 1, 2006 the fair value of all outstanding forward financial natural gas contracts was recorded as a liability on the consolidated balance sheet with a corresponding net deferred loss. The net deferred loss is recognized in net earnings over the life of the related contracts. Subsequent changes in fair value after January 1, 2006 on these financial instruments are recorded on the consolidated balance sheet with the associated unrealized gain or loss recognized in net earnings. The estimated fair value of all financial instruments is based on quoted prices or, in their absence, third party market indications and forecasts.

	June 30, 2006
Financial instrument asset – current (1)	**$ 15,571**
Financial instrument asset – long term (2)	**368**
Net financial instrument asset	**$ 15,939**

(1) Financial instruments which will settle prior to July 1, 2007.
(2) Financial instruments which will settle after June 30, 2007.

The following tables present a reconciliation of the change in the unrealized and realized gains and losses on financial instruments from January 1, 2006 to June 30, 2006:

	Net deferred amounts on transition	Mark-to-market gain (loss)	Total unrealized gain (loss)
Fair value of contracts, January 1, 2006	$ 20,453	$(20,453)	$ -
Change in fair value of contracts recorded on transition, still outstanding at June 30, 2006	-	26,589	26,589
Amortization of the fair value of contracts as at June 30, 2006	(15,881)	-	(15,881)
Fair value of contracts entered into during the period	-	5,231	5,231
Remaining deferred amount on transition, June 30, 2006	$ 4,572	-	-
Financial instrument asset, June 30, 2006	-	$ 11,367	-
Gain/(loss) on financial instruments	-	-	$ 15,939

Realized gains on financial instruments, including natural gas commodity hedges and foreign exchange price hedges, recognized in net earnings for three and six month periods ended June 30, 2006 were $3.7 and $1.5 million respectively (loss of $0.1 million for the three month period ended June 30, 2005 and a gain of $0.3 million for the six month period ended June 30, 2005).

Natural Gas commodity price hedges

At June 30, 2006 the Trust has entered into financial forward sales arrangements as follows:

Type of contract	Volumes at AECO (GJ/d)	Price ($/GJ) Fixed	Floor	Ceiling	Term
AECO fixed price	40,000	$ 7.05	-	-	July – October 2006
AECO fixed price	37,500	$ 9.12	-	-	November 2006 – March 2007
AECO collar	5,000	-	$ 9.00	$ 10.00	November 2006 – March 2007
AECO collar	5,000	-	$ 9.50	$ 11.00	November 2006 – March 2007
AECO fixed price	37,500	$ 8.00	-	-	April 2007 – October 2007
AECO fixed price	27,500	$ 9.56	-	-	November 2007 – March 2008

At January 1, 2006 the Trust recorded a deferred loss on financial instruments of $20.5 million related to existing forward commodity price contracts. The fair value of these contracts at June 30, 2006 was a gain of $6.1 million. The change in fair value, a $26.6 million gain, and $15.9 million amortization of the deferred loss have been recorded in the consolidated statements of earnings. At June 30, 2006 an $8.0 million gain was recorded in the consolidated statement of earnings related to the fair value of financial forward sales contracts entered into after January 1, 2006. No deferred gains or losses were recorded related to these financial forward sales contracts.

Foreign exchange price hedges

PET has entered into financial contracts to sell forward Canadian dollars for US dollars at a fixed exchange rate in order to mitigate the effect of exchange rate fluctuations on the Trust's realized natural gas price. Foreign exchange contracts outstanding as at June 30, 2006 are as follows:

Type of Contract	CDN$ sold (monthly)	Fixed FX rate (CDN$/US$)	Term
Financial	$ 9,000,000	1.1349	July – October 2006
Financial	$ 13,000,000	1.1255	November 2006 – March 2007
Financial	$ 7,000,000	1.1242	April – October 2007
Financial	$ 11,000,000	1.1195	November 2007 – March 2008

At June 30, 2006 a $2.8 million loss was recorded in the consolidated statement of earnings related to the fair value of financial foreign exchange contracts. No deferred gains or losses were recorded related to these financial contracts.

12. Commitments

At June 30, 2006, the Trust had entered into physical gas sales arrangements as follows:

Type of contract	Volumes at AECO (GJ/d)	Price ($/GJ) Fixed	Floor	Ceiling	Term
AECO fixed price	29,500	$ 7.40	-	$ 12.50	July – October 2006
AECO collar	5,000	-	$ 9.00	-	July – October 2006
AECO fixed price	32,500	$ 9.05	-		November 2006 – March 2007
AECO collar	5,000	-	$ 8.50	$ 11.00	November 2006 – March 2007
AECO collar	5,000	-	$ 9.00	$ 10.00	November 2006 – March 2007
AECO collar	5,000	-	$ 9.00	$ 11.00	November 2006 – March 2007
AECO fixed price	40,000	$ 8.01	-	-	April 2007 – October 2007
AECO fixed price	37,500	$ 9.69	-	-	November 2007 – March 2008

During the six months ended June 30, 2006, the Trust entered into certain physical contracts to purchase natural gas from a third party at fixed prices or price collars that were equivalent to or below the prices on existing physical contracts to sell natural gas to the same third party in order to effectively close out certain of its physical forward sales contracts at a premium. As a result of entering into these purchase contracts the Trust will collect a total of $4.0 million over the terms of the contracts. This amount has not been recorded in earnings for the current period, but will contribute to future revenues as the offsetting contracts settle over their respective terms. These contracts are as follows:

Type of Contract	Volumes at AECO (GJ/d)	PET contract obligation	Price ($/GJ) Fixed	Floor	Ceiling	Premium receivable	Term
AECO collar	5,000	Sell		$ 9.00	$ 12.50		July – October 2006
AECO collar	5,000	Buy		$ 9.00	$ 12.50	$ 947,000	July – October 2006
AECO collar	5,000	Sell		$ 8.00	$ 9.00		July – October 2006
AECO collar	5,000	Buy		$ 8.00	$ 9.00	$ 467,000	July – October 2006
AECO fixed price	13,000	Sell	$ 5.94				July – October 2006
AECO fixed price	13,000	Buy	$ 5.86			$ 125,000	July – October 2006
AECO fixed price	12,500	Sell	$ 6.14				July – October 2006
AECO fixed price	12,500	Buy	$ 5.93			$ 326,000	July – October 2006
AECO fixed price	20,000	Sell	$ 7.40				July – October 2006
AECO fixed price	20,000	Buy	$ 6.78			$ 1,525,000	July – October 2006
AECO fixed price	15,000	Sell	$ 8.87				November 2006 – March 2007
AECO fixed price	15,000	Buy	$ 8.59			$ 634,000	November 2006 – March 2007
Total						$ 4,024,000	

13. 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 AEUB as a result of recent bitumen conservation decisions. Such royalty reduction was initially prescribed in December 2004, retroactive to the date of shut-in of the gas production.

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

At June 30, 2006 PET had recorded $39.1 million ($41.8 million at December 31, 2005) for cumulative gas over bitumen royalty adjustments received to that date.

In the second quarter of 2006, PET disposed of certain shut-in gas wells in the gas over bitumen area to a third party. As part of the disposition agreement, the Trust continues to receive the gas over bitumen royalty adjustments related to the wells sold, 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. The Trust reclassifed $13.7 million from the gas over bitumen liability on the balance sheet into revenues, representing all royalty adjustments received to date in respect of the disposed wells. In future periods, royalty adjustments received in respect of these wells will be recorded directly to revenue.

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Executive Chairman

Susan L. Riddell Rose
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Kathleen Blevins
Corporate Secretary

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

Kevin J. Marjoram
Vice President, Engineering and Operations

Brett Norris
Vice President, New Ventures and Geoscience

Cameron R. Sebastian
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(2) Member of Reserves Committee
(3) Member of Environmental, Health and Safety Committee
(4) Member of Compensation Committee
(5) Member of Corporate Governance Committee

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Canadian Imperial Bank of Commerce
Bank of Nova Scotia
The Toronto-Dominion Bank
National Bank of Canada
ATB Financial

Reserve Evaluation Consultants

McDaniel & Associates Consultants Ltd.

Trustee Registrar And Transfer Agent

Computershare Trust Company of Canada