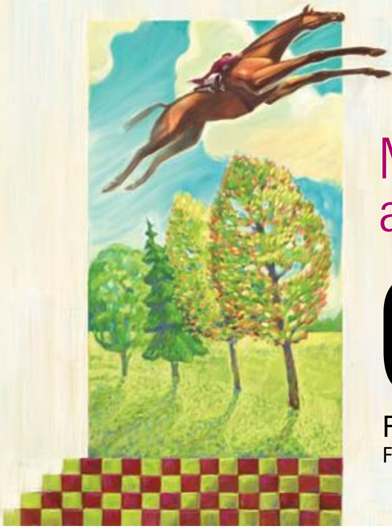

Maximizing distributions and Unitholder value

Q1

FIRST QUARTER INTERIM REPORT
For the three months ended March 31, 2006

PARAMOUNT
ENERGY TRUST

Highlights

Asset Optimization

- PET successfully completed the execution of an $80 million winter capital program in northeast Alberta, including the drilling of 78 gas wells, over 175 recompletion and workover projects and the acquisition of 875 km of 2D seismic.
- Approximately 26 MMcf/d of new production was brought onstream in April 2006.
- Planning is underway for a capital expenditure program of $20 to $45 million for the remainder of the year in all-weather access areas in the Trust's northeast Alberta East Side and Southern core areas.

Accretive Acquisitions

- The acquisition of AcquireCo, with assets in east central Alberta, closed February 16, 2006 for $94.8 million, adding 8 MMcf/d with an additional 1 to 2 MMcf/d of production to be tied in to existing gathering facilities after spring break-up. Development activity is ongoing on the acquired lands.

Maximize Cash Flow

- Average production increased to 151.5 MMcf/d, a 24 percent increase from the first quarter of 2005.
- Current actual daily production is approximately 170 MMcf/d.
- PET continued to supplement its hedging and physical forward sales portfolio in light of current weakness in natural gas prices related to historically high gas storage levels. PET's weighted average price on financial hedges and physical forward sales contracts for an average of 73,500 GJ/d for the period from April 1 to December 31, 2006 is $8.13 per GJ.

Healthy Balance Sheet

- The offering of $100 million of 6.25% convertible unsecured subordinated debentures with a conversion price of $23.80 per Trust Unit closed on April 6, 2006.
- The Trust's borrowing base on its credit facility is $310 million, with current bank debt drawn to $223 million.

Maximize Distributions and Unitholder Value

- Distributions for the first quarter of 2006 totaled $0.72 per Trust Unit.
- PET announced its ninth consecutive distribution of $0.24 per Trust Unit for May 2006.

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

($Cdn thousands except volume and per Trust Unit amounts)	Three Months Ended March 31 **2006**	2005	% Change
Financial			
Revenue before royalties	**112,639**	75,947	48
Cash flow [(1)]	**61,112**	40,801	50
Per Trust Unit [(2)]	**0.74**	0.62	19
Net earnings	**7,969**	2,199	262
Per Trust Unit [(2)]	**0.10**	0.03	233
Distributions	**59,954**	43,602	38
Per Trust Unit [(3)]	**0.72**	0.66	9
Payout ratio (%) [(1)]	**98.1**	106.9	(8)
Total assets	**942,188**	599,938	57
Net bank and other debt outstanding [(4)]	**328,892**	239,926	37
Convertible debentures	**62,236**	34,289	82
Total net debt [(4)]	**391,128**	274,215	43
Unitholders' equity	**356,895**	233,148	53
Capital expenditures			
Exploration and development	**80,301**	40,228	100
Acquisitions, net of dispositions	**89,412**	26,798	234
Other	**110**	150	(27)
Net capital expenditures	**169,823**	67,176	153
Trust Units outstanding (thousands)			
End of period	**83,466**	66,294	26
Weighted average	**83,058**	65,849	26
Incentive Rights outstanding	**1,758**	1,303	35
Trust Units outstanding at April 28, 2006	**83,605**	-	-
Operating			
Production			
Total natural gas (Bcf)	**13.6**	11.0	24
Daily average natural gas (MMcf/d)	**151.5**	122.0	24
Gas over bitumen deemed production (MMcf/d) [(5)]	**21.5**	23.4	(8)
Average daily (actual and deemed - MMcf/d) [(5)]	**173.0**	145.4	19
Per Trust Unit (cubic feet/d/Unit) [(2)]	**2.08**	2.21	(6)
Average prices			
Natural gas ($/Mcf), pre-hedging	**8.26**	6.92	19
Natural gas ($/Mcf), including hedging	**8.09**	6.95	16
Land (thousands of net acres)			
Undeveloped land holdings	**1,079**	766	41
Drilling			
Wells drilled (gross/net)			
Gas	**84/73.3**	34/27.8	147/164
Dry	**3/1.7**	3/3.0	-/(43)
Total	**87/75.0**	37/30.8	135/144
Success rate (% gross/% net)	**97/98**	92/90	5/9

(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. Total net debt includes convertible debentures.

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

Corporate

In the first quarter of 2006 PET continued to enhance the sustainability of its business model. During the quarter the Trust completed the most significant winter capital program in its history, with $80 million in total expenditures on low-risk drilling, recompletions, tie-ins and facilities expansion and optimization projects designed to offset natural declines primarily in its three core areas in northeast Alberta. As a result of this program 26 MMcf/d of production net to PET has been added over and above the 2006 base forecast.

The acquisition of AcquireCo in February allowed PET to expand its geographical focus further outside of its winter-only access operating areas, while maintaining its focus on shallow natural gas. The prospective lands acquired are still early in the development stage and will add considerably to PET's drilling inventory for the remainder of 2006 and beyond. PET staff are working closely with the AcquireCo management team, who were retained through to the end of the second quarter of 2006 as part of the acquisition agreement, to continue to develop prospects to enhance the value of the acquisition and provide opportunities for production additions that meet the Trust's economic hurdle rates and risk profile.

Production for the first quarter of 2006 totaled 151.5 MMcf/d, a 24 percent increase from the first 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 PET's current production level of approximately 170 MMcf/d. The incremental production volumes from first quarter capital activities, combined with cash flow stability provided by the Trust's prudent risk management portfolio of physical and financial forward natural gas contracts, have allowed PET to maintain its monthly distribution of $0.24 per Trust Unit despite a strong downward trend in short-term natural gas prices. This reaffirms the Trust's commitment to maximizing returns to Unitholders.

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 fit PET's acquisition criteria. Through the Trust's industry-leading Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan") $11.2 million was invested by Unitholders during the current quarter, further contributing to PET's relatively conservative leverage position at March 31, 2006, despite significant capital and acquisitions expenditures during the period.

Planning is currently underway on the Trust's capital program for the remainder of 2006, focusing on the Southern core area including continued activity on the AcquireCo Assets. PET plans to spend $20 to $45 million on these activities in the last three quarters of 2006, targeting additional low-risk production additions to offset declines in the Southern area and to further enhance the sustainability of the Trust's monthly distribution.

Cash flow for the first quarter of $61.1 million, combined with distributions of $60.0 million, translated into a payout ratio of 98%. Consistent with prior years, the Trust spent approximately a third of its total operating cost budget for 2006 in the first three months of the year due to the winter only access nature of the majority of the Trust's asset base, which typically increases the payout ratio for the first quarter.

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 months ended March 31, 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 months ended March 31, 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 legal advisories regarding forward-looking information contained in the "Forward Looking Information" section of this MD&A. The date of this MD&A is May 11, 2006.

First quarter highlights

($Cdn millions except per Trust Unit, percent and volume data)	Three months ended March 31 2006	2005
Cash flow (1)	**$ 61.1**	$ 40.8
Per Trust Unit (1)	**$ 0.74**	$ 0.62
Net earnings	**$ 8.0**	$ 2.2
Distributions	**$ 60.0**	$ 43.6
Per Trust Unit	**$ 0.72**	$ 0.66
Payout ratio (%) (1)	**98.1**	106.9
Production (MMcf/d) (2)		
Daily average	**151.5**	122.0
Gas over bitumen deemed	**21.5**	23.4
Total average daily (actual and deemed)	**173.0**	145.4

(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 March 31 2006	2005
West Side	**45.5**	35.4
East Side	**26.5**	28.8
Athabasca	**70.1**	51.1
Southern	**9.4**	6.7
Total	**151.5**	122.0
Deemed production	**21.5**	23.4
Total actual plus deemed production	**173.0**	145.4

Average production increased 24 percent to 151.5 MMcf/d for the three months ended March 31, 2006 as compared to 122.0 MMcf/d in the first quarter of 2005. The 34 percent increase in combined production in the West Side and Athabasca core areas is due primarily to 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 partial effect of 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 19 percent to 173.0 MMcf/d from 145.4 MMcf/d in the first quarter of 2005.

Capital expenditures

	Three months ended March 31	
Capital expenditures ($ thousands)	**2006**	2005
Exploration and development expenditures [(1)]	**80,301**	40,228
Acquisitions	**90,882**	26,797
Dispositions	**(1,470)**	-
Other	**110**	151
Total capital expenditures	**169,823**	67,176

(1) Exploration and development expenditures for the three months ended March 31, 2006 include approximately $8.3 million in exploration costs (three months ended March 31, 2005 – nil) 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.

PET completed its successful winter capital program in northeast Alberta in early April. The Trust invested approximately $80 million in exploration and development spending in its winter-access properties with new drilling, completions and tie-ins, recompletion and facilities optimization work distributed throughout the Trust's core areas in northeast and east central Alberta. The program included the drilling of 87 gross wells (75.0 net) resulting in 84 gross gas wells (73.3 net) and an extensive recompletion and workover program of over 175 wells. The expenditures resulted in approximately 26 MMcf/d of new production in excess of the base estimate from the Trust's external reserve report dated December 31, 2005.

For the remainder of 2006 PET intends to focus its capital activities in the year-round access areas in its Southern core area. New drilling in southern and east central Alberta and Saskatchewan, as well as further participation in the Trust's non-operated coal bed methane project at Craigmyle will be initiated once ground conditions permit access to roads and leases. PET plans to spend $20 to $45 million on these activities in the last three quarters of 2006.

PET successfully closed the acquisition of AcquireCo on February 16, 2006 for $90.8 million, or $94.8 million including assumption of net debt of $4.0 million. Production from the AcquireCo Assets is 100 percent natural gas-weighted, over 90 percent operated and is currently approximately 8 MMcf/d, with an additional 1 to 2 MMcf/d of production additions from the nine well drilling program to be tied in to existing gathering facilities after spring break-up. The AcquireCo Assets are located southeast of PET's Athabasca core area in east-central Alberta and as at the closing date offered over 50 shallow gas drilling and development prospects that meet the Trust's risk profile on 54,600 net acres of undeveloped year-round access lands.

Marketing

Natural gas prices

	Three months ended March 31	
Natural gas prices ($/Mcf, except percent amounts)	**2006**	2005
Reference prices		
AECO Monthly Index	**$ 9.27**	$ 6.69
AECO Daily Index	**$ 7.50**	$ 6.89
AECO blended average [(1)]	**$ 8.39**	$ 6.79
Alberta Gas Reference Price [(3)]	**$ 8.21**	$ 6.42
Average PET prices		
Before hedging	**$ 8.26**	$ 6.92
% AECO blended average (%)	**98**	102
After hedging [(2)]	**$ 8.09**	$ 6.95
% AECO blended average (%)	**96**	102

(1) AECO blended average refers to the average of the AECO Daily and Monthly Indexes for the period. PET sells natural gas on both AECO daily and monthly markets.

(2) Natural gas price after hedging includes realized gains and losses on financial forward contracts and options.

(3) Alberta Gas Reference Price for March 2006 is an estimate, as the actual price has not yet been posted.

Realized natural gas prices increased by 16 percent for the three months ended March 31, 2006 to $8.09 per Mcf from $6.95 per Mcf in 2005 largely as a result of a 24 percent increase in AECO blended average index prices from quarter to quarter. Before hedging, PET's realized natural gas price was $8.26 per Mcf for the three months ended March 31, 2006 compared to $6.92 per Mcf for the same period in 2005.

Risk Management

To ensure 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.

At March 31, 2006, the Trust had entered into financial and physical forward sales arrangements as follows:

Financial hedges and physical forward sales contracts at March 31, 2006

Type of contract	Volumes at AECO (GJ/d)	Price ($/GJ) Fixed	Floor	Ceiling	Term
Financial	30,000	$ 7.48	-	-	April – October 2006
Physical	42,500	$ 7.64	-	-	April – October 2006
Physical	5,000	-	$ 9.00	$12.50	April – October 2006
Period Total	77,500		$ 7.67(1)		April – October 2006
Financial	30,000	$ 9.07	-	-	November 2006 – March 2007
Financial	5,000	-	$ 9.50	$11.00	November 2006 – March 2007
Financial	5,000	-	$ 9.00	$10.00	November 2006 – March 2007
Physical	32,500	$ 9.05	-	-	November 2006 – March 2007
Physical	5,000	-	$ 9.00	$11.00	November 2006 – March 2007
Physical	5,000	-	$ 9.00	$10.00	November 2006 – March 2007
Physical	5,000	-	$ 8.50	$11.00	November 2006 – March 2007
Period Total	87,500		$ 9.04(1)		November 2006 – March 2007
Financial	37,500	$ 8.00	-	-	April – October 2007
Physical	37,500	$ 8.04	-	-	April – October 2007
Period Total	75,000		$ 8.02		April – October 2007
Financial	22,500	$ 9.42	-	-	November 2007 – March 2008
Physical	17,500	$ 9.03	-	-	November 2007 – March 2008
Period Total	40,000		$ 9.25		November 2007 – March 2008

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

PET continued to supplement its risk management program after the end of the first quarter. Financial and physical forward sales arrangements at May 1, 2006 are as follows:

Financial hedges and physical forward sales contracts at May 1, 2006

Type of contract	Volumes at AECO (GJ/d)	Price ($/GJ) Fixed	Floor	Ceiling	Term
Financial	30,000	$ 7.48	-	-	June – October 2006
Physical	32,500	$ 7.91	-	-	June – October 2006
Physical	5,000	-	$ 9.00	$12.50	June – October 2006
Period Total	67,500		$ 7.80(1)		June – October 2006
Financial	32,500	$ 9.20	-	-	November 2006 – March 2007
Financial	5,000	-	$ 9.50	$11.00	November 2006 – March 2007
Financial	5,000	-	$ 9.00	$10.00	November 2006 – March 2007
Physical	32,500	$ 9.05	-	-	November 2006 – March 2007
Physical	5,000	-	$ 9.00	$11.00	November 2006 – March 2007
Physical	5,000	-	$ 9.00	$10.00	November 2006 – March 2007
Physical	5,000	-	$ 8.50	$11.00	November 2006 – March 2007
Period Total	90,000		$ 9.09(1)		November 2006 – March 2007
Financial	37,500	$ 8.00	-	-	April – October 2007
Physical	37,500	$ 8.04	-	-	April – October 2007
Period Total	75,000		$ 8.02		April – October 2007
Financial	22,500	$ 9.42	-	-	November 2007 – March 2008
Physical	32,500	$ 9.61	-	-	November 2007 – March 2008
Period Total	55,000		$ 9.53		November 2007 – March 2008

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

During the three months ended March 31, 2006, the Trust entered into certain physical contracts to purchase natural gas from a third party at price collars that were equivalent to existing physical contracts to sell natural gas to the same third party to effectively close out certain of its physical forward sales contracts. As a result of entering into these purchase contracts the Trust will collect premiums totaling $2.5 million over the term 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:

Physical forward sales contracts offset in the first quarter of 2006

Type of contract	Volumes at AECO GJ/d	PET contract obligation	Price ($/GJ) Floor	Price ($/GJ) Ceiling	Premium receivable	Term
AECO collar	5,000	sell	$ 9.00	$ 12.50	-	April – October 2006
AECO collar	5,000	buy	$ 9.00	$ 12.50	$ 1,647,800	April – October 2006
AECO collar	5,000	sell	$ 8.00	$ 9.00	-	April – October 2006
AECO collar	5,000	buy	$ 8.00	$ 9.00	$ 813,200	April – October 2006
Total					$ 2,461,000	

Financial results

Revenue

Revenue ($ thousands)	Three months ended March 31 2006	2005
Natural gas revenue, before hedging	**112,639**	75,947
Realized gains (losses) on financial instruments (1)	**(2,264)**	399
Total revenue	**110,375**	76,346

(1) Realized gains (losses) on financial instruments include settlement of financial forward contracts and options.

Natural gas revenue before hedging increased 48 percent to $112.6 million for the three months ended March 31, 2006 compared to $75.9 million for the three months ended March 31, 2005 due to higher production levels and increased natural gas prices. Realized losses on financial forward contracts totaled $2.3 million for the period, as compared to realized gains of $0.4 million for the three months ended March 31, 2005. The Trust includes realized gains and losses on financial forward contracts in its calculation of realized natural gas prices, after hedging.

The Trust recorded an unrealized gain on financial instruments of $7.2 million for the three months ended March 31, 2006, reflecting the change in the fair value of financial forward contracts during the period (see "Change in accounting policy" in this MD&A).

Cash flow

	Three months ended March 31			
	2006		2005	
Cash flow reconciliation	**$ millions**	**$/Mcf**	$ millions	$/Mcf
Production volume (Bcf)	**13.6**		11.0	
Revenue, including realized gains and losses on financial instruments	**110.4**	**8.09**	76.3	6.95
Royalties	**(21.9)**	**(1.61)**	(14.6)	(1.33)
Operating costs	**(22.7)**	**(1.67)**	(16.6)	(1.51)
Transportation costs	**(3.4)**	**(0.25)**	(3.0)	(0.27)
Operating netback from production	**62.4**	**4.56**	42.1	3.84
Gas over bitumen royalty adjustments	**6.2**	**0.46**	4.8	0.43
Lease rentals	**(0.9)**	**(0.06)**	(1.0)	(0.10)
General and administrative (1)	**(3.0)**	**(0.22)**	(2.6)	(0.23)
Interest on bank and other debt	**(2.6)**	**(0.19)**	(1.6)	(0.15)
Interest on convertible debentures (1)	**(1.0)**	**(0.07)**	(0.7)	(0.06)
Capital taxes	**0.0**	**0.00**	(0.2)	(0.01)
Cash flow (1)(2)	**61.1**	**4.48**	40.8	3.72

(1) Excludes non-cash items

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

For the three months ended March 31, 2006, PET's average royalty rate was 19.8 percent compared to 19.3 percent for the same period in 2005. The increase in the average royalty rates is primarily a result of the increase in the Alberta Gas Reference Price in the first quarter of 2006 compared to 2005, offset by crown royalty credit adjustments of $1.0 million relating to prior periods received in the current quarter.

Production costs increased to $22.7 million ($1.67 per Mcf) in the three months ended March 31, 2006 from $16.6 million ($1.51 per Mcf) for the same period in 2005. Unit-of-production costs have increased 11 percent in 2006 due to fixed operating costs related to the operation of additional plants 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 $1.20 to 1.25 per Mcf for 2006.

Higher realized natural gas prices combined with higher production volumes, offset by higher royalties and increased production and transportation costs resulted in a $20.3 million increase in PET's operating netback to $62.4 million for the three months ended March 31, 2006 from $42.1 million for the three months ended March 31, 2005.

Operating netback reconciliation ($ millions)

Production increase	$ 18.5
Price increase, including realized gains and losses on financial instruments	15.5
Royalty increase	(7.2)
Transportation cost increase	(0.4)
Operating cost increase	(6.1)
Increase in net operating income	$ 20.3

General and administrative expenses were $3.3 million for the three months ended March 31, 2006 compared to $2.9 million for the three months ended March 31, 2005. The scale of PET's operations increased significantly with the Northeast Alberta Acquisition completed in 2005 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 $0.22 per Mcf for the three months ended March 31, 2006 as compared to $0.23 per Mcf in 2005.

Interest on bank and other debt totaled $2.6 million for the three months ended March 31, 2006, as compared to $1.6 million for the comparable period in 2005. Interest expense has increased due to the partial effect of debt financing costs for the AcquireCo acquisition in February 2006 as well as higher short-term interest rates in the first quarter of 2006 as compared to 2005.

Interest on convertible debentures for the three months ended March 31, 2006 increased by $0.3 million compared to the three months ended March 31, 2005 due primarily to the issuance of $100 million of 6.25% convertible unsecured subordinated debentures (the "2005 6.25% Debentures") in April 2005, offset somewhat by the conversion of $27.2 million of the Trust's 8% convertible unsecured subordinated debentures (the "8% Debentures") and $44.5 million of the 2005 6.25% Debentures from April 1, 2005 to March 31, 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 first 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 current deemed production is approximately 21.5 MMcf/d.

For the three months ended March 31, 2006 the Trust received $6.2 million in gas over bitumen royalty adjustments, a 31 percent increase from the $4.8 million received in the first quarter of 2005, primarily due to higher Alberta Gas Reference Prices in 2006 as compared to the prior year. 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 March 31, 2006 to $48.0 million. Royalty adjustments, although not included in earnings, are recorded as a component of cash flow and as such are considered distributable income.

The above factors combined to increase cash flow from operations by 50 percent to $61.1 million for the three months ended March 31, 2006 from $40.8 million in the 2005 period. Cash flow per Trust Unit increased 19 percent to $0.74 from $0.62 per Trust Unit for the comparable quarter in 2005.

Earnings

Exploration expenses increased to $9.2 million for the three months ended March 31, 2006 from $1.0 million for the first 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 $35.0 million in the first quarter of 2005 to $45.3 million in 2006 due to increased production volumes and a slight increase in the Trust's depletion rate. PET's depletion rate was $3.32 per Mcf in the three months ended March 31, 2006 as compared to $3.18 per Mcf in 2005.

The Trust reported net earnings of $8.0 million or $0.10 per basic and diluted Trust Unit for the three months ended March 31, 2006 as compared to $2.2 million or $0.03 per basic and diluted Trust Unit for the 2005 period. The increase from 2005 is primarily a result of increased revenues due to higher production levels, higher natural gas prices and $7.2 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 higher exploration costs and DD&A expense.

Summary of quarterly results

($ thousands except per Trust Unit amounts)	Mar 31, 2006	Dec 31, 2005	Sept 30, 2005	Three months ended June 30, 2005
Natural gas revenues before royalties	$ 112,639	$ 129,233	$ 118,928	$ 100,234
Cash flow (1)	$ 61,112	$ 78,200	$ 74,726	$ 66,491
Per Trust Unit - basic	$ 0.74	$ 0.96	$ 0.95	$ 0.90
Net earnings	$ 7,969	$ 17,899	$ 30,339	$ 11,433
Per Trust Unit - basic	$ 0.10	$ 0.22	$ 0.39	$ 0.16
- diluted	$ 0.10	$ 0.22	$ 0.38	$ 0.15

($ thousands except per Trust Unit amounts)	Mar 31, 2005	Dec 31, 2004	Sept 30, 2004	Three months ended June 30, 2004
Natural gas revenues before royalties	$ 75,947	$ 79,665	$ 59,156	$ 49,904
Cash flow (1)	$ 40,801	$ 56,521	$ 31,301	$ 29,913
Per Trust Unit - basic	$ 0.62	$ 0.87	$ 0.52	$ 0.52
Net earnings (loss)	$ 2,199	$ (29,696)	$ 4,813	$ 5,146
Per Trust Unit - basic	$ 0.03	$ (0.46)	$ 0.08	$ 0.11
- diluted	$ 0.03	$ (0.46)	$ 0.08	$ 0.11

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

Natural gas revenues and cash flow have trended steadily higher over the quarters shown above until the first quarter of 2006. The increase is primarily a result of higher production volumes due to acquisition activity in the second half of 2004 and early 2005, as well as increased natural gas prices over the two-year period with the exception of the three months ended March 31, 2006 where PET's realized natural gas price dipped to $8.09 per Mcf from $9.14 per Mcf for the fourth quarter of 2005.

The increased net earnings in the second, third and fourth quarters of 2005 are due to higher natural gas revenues, offset somewhat by higher royalties and DD&A expenses as compared to prior quarters. The net loss in the fourth quarter of 2004 was a result of an after-tax write-down of property, plant and equipment of $39 million pertaining to the Trust's Saskatchewan properties. The lower earnings in the first quarter of 2006 are due to higher DD&A charges compared to prior quarters and $7.6 million in seismic costs expensed during the quarter offset somewhat by an unrealized gain on financial instruments of $7.2 million.

Liquidity and capital resources

Net debt ($ thousands except per Trust Unit and percent amounts)	**March 31, 2006**	December 31, 2005
Bank and other debt	**282,280**	168,106
Convertible debentures	**62,236**	64,888
Working capital deficiency (surplus) (2)	**46,612**	(1,131)
Net debt	**391,128**	231,863
Trust Units outstanding (thousands)	**83,466**	82,482
Market price at end of period ($/Trust Unit)	**19.89**	22.17
Market value of Trust Units	**1,660,139**	1,828,626
Total market capitalization (1)	**2,051,267**	2,060,489
Net debt as a percentage of total capitalization (%)	**19.1**	11.3
Cash flow for the period (1)	**61,112**	260,218
Annualized cash flow (1)	**244,448**	260,218
Net debt to annualized cash flow ratio (times) (1)	**1.6**	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.

PET has a demand credit facility with a syndicate of Canadian chartered banks. The revolving feature of the facility expires on May 30, 2006 if not extended. Pursuant to the terms of the credit agreement, the Trust intends 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 $282.3 million at March 31, 2006, as compared to $168.1 million at December 31, 2005 as a result of expenditures related to the winter capital program and the use of debt financing for the AcquireCo acquisition during the quarter. In addition to amounts outstanding under the credit facility, PET has outstanding letters of credit in the amount of $4.37 million.

At March 31, 2006 PET had $55.5 million in 2005 6.25% Debentures outstanding, of which $0.4 million was classified as equity on the Trust's balance sheet, and $7.1 million of 8% Debentures outstanding. The fair values of the convertible debentures at March 31, 2006 were $59.9 million and $9.9 million, respectively. Fair values of debentures are calculated by multiplying the number of debentures outstanding at March 31, 2006 by the quoted market price per debenture at that date. During the first quarter $2.4 million of the 2005 6.25% Debentures and $0.3 million of the 8% Debentures were converted at conversion rates of $19.35 per Trust Unit and $14.20 per Trust Unit, respectively, resulting in the issuance of 145,000 Trust Units.

PET's working capital deficiency increased to $46.6 million at March 31, 2006 as compared to a surplus of $1.1 million at December 31, 2005. PET will typically experience a working capital deficiency in the first quarter of the year, as a significant portion of the costs related to the Trust's winter capital program were included in accounts payable and accrued liabilities at the balance sheet date.

Net debt to annualized cash flow rose to 1.6 times for the quarter ended March 31, 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 during the current period and the Trust's significant winter capital program.

Cumulative distributions for the first quarter of 2006 totaled $0.72 per Trust Unit consisting of $0.24 per Trust Unit paid on February 15, March 15 and April 17. The Trust's payout ratio, which is the ratio of distributions to cash flow, was 98.1 percent in the current quarter, as compared to 106.9 percent for the first quarter of 2005. PET's payout ratio is often highest in the first quarter of the year, as production additions from the winter capital program are typically fully realized in the second quarter. The payout ratio in future periods will largely be determined by production levels resulting from the AcquireCo properties and first quarter capital spending, as well as natural gas prices, which have experienced significant volatility in 2006.

On April 6, 2006 PET issued $100 million in 6.25% convertible unsecured subordinated debentures (the "2006 6.25% Debentures") for net proceeds of $95.5 million. The 2006 6.25% Debentures have a maturity date of April 30, 2011 and are convertible into Trust Units at a price of $23.80 per Trust Unit. 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, 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") $11.2 million was invested by Unitholders during the three months ended March 31, 2006 and a total of 585,000 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 $0.24 per Trust Unit, for the remainder 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 April to December 2006 ($/GJ)		
Cash flow sensitivity analysis	$6.00	$7.00	$8.00
Natural gas production (MMcf/d)	158	158	158
Realized gas price (1) ($/Mcf)	7.29	7.87	8.48
Cash flow (2) ($million/month)	21.1	23.3	25.6
Per Trust Unit ($/Unit/month)	0.252	0.278	0.305
Payout ratio (2) (%)	95%	86%	79%
Ending net debt ($million)	381	362	341
Ending net debt to cash flow ratio (3) (times)	1.5	1.3	1.2

(1) PET's weighted average forward price on an average of 73,500 GJ/d for the period from April 1 to December 31, 2006 is $8.13/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 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 from 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 provided by operating activities, as follows:

Cash flow GAAP reconciliation ($ thousands except per Trust Unit amounts)	For the three months ended March 31 2006	2005
Cash provided by operating activities	$ 70,080	$ 40,960
Exploration costs (1)	8,335	-
Settlement of asset retirement obligations	538	-
Changes in non-cash operating working capital	(17,841)	(159)
Cash flow	$ 61,112	$ 40,801
Cash flow per Trust Unit (2)	$ 0.74	$ 0.62

(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.

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.

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 March 31, 2006, as well as fair values of other financial forward natural gas contracts as at March 31, were included in net earnings for the quarter. The combination of the change in fair value during the period and amortization of the fair values recorded at January 1, 2006 was an unrealized gain on financial instruments of $7.2 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 months ended March 31, 2006.

As the change in accounting policy was applied prospectively there is no related impact on earnings for previous periods.

Critical accounting estimates

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

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. Industry comment was solicited prior to February 14, 2006 however the AEUB has not yet announced if or how it will proceed with respect to this matter. PET has current production of approximately 5.8 MMcf/d from the Bluesky-Gething formations in the portion of the Panny field and the Darwin field which are located within the Peace River Oil Sands Area. 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. This production represents less than 5% of PET's current production. The Government of Alberta has not made comment as to whether the Gas over Bitumen Royalty Adjustment applied to shut-in gas in the Wabiskaw-McMurray in the Athabasca Oils Sands Area would apply to these other regions. There has been no expression of concern from bitumen resource owners in the Panny or Darwin areas.

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 should not be construed as 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	**March 31, 2006**	December 31, 2005
($ thousands)	(unaudited)	
Assets		
Current assets		
Accounts receivable	**$ 44,979**	$ 57,837
Financial instruments (notes 2 and 11)	**11,740**	-
	56,719	57,837
Property, plant and equipment (notes 4 and 5)	**851,158**	728,173
Goodwill	**29,129**	29,129
Other assets (note 3)	**5,182**	5,269
	$ 942,188	$ 820,408
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	**$ 71,559**	$ 36,910
Distributions payable	**20,032**	19,796
Bank and other debt (note 6)	**282,280**	168,106
	373,871	224,812
Financial instruments (notes 2 and 11)	**4,531**	-
Gas over bitumen royalty adjustments (note 13)	**48,019**	41,789
Asset retirement obligations (note 10)	**96,636**	94,276
Convertible debentures (note 7)	**62,236**	64,888
Unitholders' equity		
Unitholders' capital (note 8)	**784,784**	769,210
Equity component of convertible debentures	**470**	490
Contributed surplus (note 9)	**2,735**	4,052
Deficit	**(431,094)**	(379,109)
	356,895	394,643
	$ 942,188	$ 820,408

See accompanying notes
Basis of presentation: note 1
Commitments: note 12
Contingencies: notes 11 and 13
Subsequent event: note 14

John W. Peltier
Director

Donald J. Nelson
Director

Interim Consolidated Statements of Earnings and Deficit

(Unaudited)

	Three Months Ended March 31	
	2006	2005
($ thousands except per Unit amounts)		
Revenue		
Natural gas	**$ 112,639**	$ 75,947
Royalties	**(21,874)**	(14,639)
Gain on financial instruments (notes 2 and 11)	**4,945**	399
	95,710	61,707
Expenses		
Operating	**22,747**	16,604
Transportation costs	**3,379**	2,978
Exploration expenses	**9,186**	1,046
General and administrative	**3,341**	2,946
Interest	**2,647**	1,638
Interest on convertible debentures	**1,164**	667
Depletion, depreciation and accretion	**45,294**	34,994
	87,758	60,873
Earnings before income taxes	**7,952**	834
Future income tax reduction	**-**	1,519
Capital taxes	**17**	(154)
	17	1,365
Net earnings	**7,969**	2,199
Deficit, beginning of period	**(379,109)**	(219,776)
Distributions	**(59,954)**	(43,602)
Deficit, end of period	**$ (431,094)**	$ (261,179)
Earnings per Trust Unit (note 8(c))		
Basic and diluted	**$ 0.10**	$ 0.03
Distributions per Trust Unit	**$ 0.72**	$ 0.66

See accompanying notes

Interim Consolidated Statements of Cash Flows

(Unaudited)

	Three Months Ended March 31	
	2006	2005
($ thousands)		
Cash provided by (used for)		
Operating activities		
Net earnings	**$ 7,969**	$ 2,199
Items not involving cash		
Depletion, depreciation and accretion	**45,294**	34,994
Trust Unit-based compensation	**336**	368
Future income tax reduction	**-**	(1,519)
Unrealized gain on financial instruments	**(7,209)**	-
Amortization of other assets	**156**	-
Gas over bitumen royalty adjustments	**6,231**	4,759
Expenditures on asset retirement obligations	**(538)**	-
Change in non-cash working capital	**17,841**	159
	70,080	40,960
Financing activities		
Issue of Trust Units	**6,945**	2,534
Distributions to Unitholders	**(55,588)**	(40,917)
Change in bank and other debt	**114,174**	42,368
Change in non-cash working capital and other assets	**816**	393
	66,347	4,378
	136,427	45,338
Investing activities		
Acquisition of investments	**-**	(1,243)
Acquisition of properties and corporate assets	**(90,992)**	(26,948)
Exploration and development expenditures	**(71,966)**	(40,228)
Proceeds on sale of property and equipment	**1,470**	-
Change in non-cash working capital and asset retirement obligation	**25,061**	23,081
	$ (136,427)	$ (45,338)
Change in cash	**-**	-
Cash, beginning of period	**-**	-
Cash, end of period	**$ -**	$ -
Interest paid	**$ 3,095**	$ 3,771
Taxes paid	**$ 125**	$ 35

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 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 March 31, 2006, as well as fair values of other financial forward natural gas contracts as at March 31, 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 March 31, 2006, $12.5 million of the initial deferred loss has been amortized into net earnings.

3. Other assets

	March 31, 2006	December 31, 2005
Convertible debenture issue costs	**$ 2,182**	$ 2,269
Investment	**3,000**	3,000
	$ 5,182	$ 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 months ended March 31, 2006, amortization of $0.2 million (2005 - nil) has been recognized in these consolidated financial statements.

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

	March 31, 2006	December 31, 2005
Petroleum and natural gas properties	**$ 1,439,908**	$ 1,274,639
Asset retirement costs	**89,203**	87,990
Corporate assets	**16,131**	16,020
	1,545,242	1,378,649
Accumulated depletion and depreciation	**(694,084)**	(650,476)
	$ 851,158	$ 728,173

Property, plant and equipment costs at March 31, 2006 included $90.3 million (March 31, 2005 - $68.5 million) currently not subject to depletion.

5. Corporate acquisition

On February 16, 2006 PET acquired a private Alberta company ("AcquireCo") for consideration of $90.8 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 is subject to change.

Property, plant and equipment	$ 93,176
Land	2,800
Working capital deficiency	(4,465)
Cash	551
Asset retirement obligation	(1,213)
Cash consideration paid	$ 90,849

6. Bank and other debt

PET has a revolving credit facility with a syndicate of Canadian Chartered Banks (the "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 $4.37 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 March 31, 2006 was 4.66%.

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 (the "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 three month period ended March 31, 2006, $2.4 million of 6.25% Convertible Debentures were converted resulting in the issuance of 124,285 Trust Units.

The Trust's 8% convertible unsecured subordinated debentures (the "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 three month period ended March 31, 2006, $0.3 million of 8% Convertible Debentures were converted, resulting in the issuance of 20,912 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 March 31, 2006, the Trust had $7.1 million in 8% Convertible Debentures outstanding with a fair market value of $9.9 million, and $55.5 million in 6.25% Convertible Debentures outstanding with a fair market value of $59.9 million.

	8% Series		6.25% Series		
	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
Accretion of non-cash interest expense	-	-	-	29	29
Converted into Trust Units	(297)	(297)	(2,405)	(2,384)	(2,681)
Balance, March 31, 2006	**7,057**	**$ 7,057**	**55,501**	**$ 55,179**	**$ 62,236**

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 Distribution Reinvestment Plan	584,642	11,170
Units issued pursuant to conversion of debentures	145,197	2,702
Issue costs on convertible debentures converted to Trust Units	-	(92)
Balance, March 31, 2006	**83,466,433**	**$ 784,784**

c) Per Unit Information

Basic earnings per Trust Unit are calculated using the weighted average number of Trust Units outstanding during the three month period ended March 31, 2006 of 83,058,288 (2005 – 65,849,320). 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 430,252 net Trust Units were added to the weighted average number of Trust Units outstanding during the three month period ended March 31, 2006 (2005 – 521,264 net Trust Units) for the dilutive effect of Incentive Rights. In computing diluted earnings per Trust Unit 235,000 Incentive Rights were excluded as the exercise prices exceeded the market price at March 31, 2006 (2005 – nil).

d) Redemption Right

Unitholders may redeem their Trust Units at any time by delivering their 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 (the "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 $0.3 million for the three months ended March 31, 2006 ($0.4 million for the three months ended March 31, 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 March 31, 2006 a combined total of 3,963,838 (2005 – 3,963,838) Trust Units had been reserved under the Unit Incentive Plan and the Bonus Rights Plan (see note 9 (b)). As at March 31, 2006 48,250 Incentive Rights granted under the Unit Incentive Plan had vested but were unexercised (12,500 as of March 31, 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 – 3.7**	1.7 – 3.7
Expected volatility (%)	**21.5**	21.0
Risk-free interest rate (%)	**3.85 – 4.11**	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	**$ 3.15**	$ 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	19.00	432,250
Exercised	0.55	(254,750)
Cancelled	12.23	(68,125)
Balance, March 31, 2006	**$ 14.24**	**1,757,500**
Incentive Rights exercisable, March 31, 2006	**$ 8.60**	**48,250**

The following summarizes information about Incentive Rights outstanding at March 31, 2006 assuming the reduced exercise price described above:

Range of exercise prices	Number outstanding at March 31, 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	1.8	$ 0.001	-	-
$7.08 - $7.19	135,000	2.6	7.14	37,500	$ 7.13
$7.89 - $12.85	329,000	3.5	8.65	2,500	9.32
$13.91 - $17.98	454,250	4.3	15.56	8,250	15.06
$18.17 - $22.24	607,250	4.8	19.49	-	-
Total	**1,757,500**	**3.8**	**$ 14.24**	**48,250**	**$ 8.60**

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
Trust Unit-based compensation expense	336
Transfer to Unitholders' capital on exercise of Incentive Rights	(1,653)
Balance, as at March 31, 2006	**$ 2,735**

b) Bonus rights plan

PET has implemented a bonus rights plan (the "Bonus Rights Plan") for certain officers, employees and direct and indirect service providers of the Administrator ("Service Providers"). 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.

For the three months ended March 31, 2006 nil compensation expense was recorded in respect of the Bonus Rights granted (three months ended March 31, 2005 – nil). There were no Bonus Rights granted, vested or exercised during the current period.

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)
Accrued distributions	2,457
Balance, December 31, 2005	26,709
Accrued distributions	1,069
Balance, March 31, 2006	**27,778**

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 the 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 $96.6 million as at March 31, 2006 based on an undiscounted total future liability of $193.6 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:

	March 31, 2006	December 31, 2005
Obligation, beginning of period	**$ 94,276**	$ 34,116
Obligations incurred	**-**	8,232
Obligations acquired	**1,213**	13,267
Revisions to estimates	**-**	35,704
Expenditures for obligations during the period	**(538)**	(660)
Accretion expense	**1,685**	3,617
	$ 96,636	$ 94,276

11. Financial instruments

As disclosed in note 2, on January 1, 2006 the fair value of all outstanding forward financial natural gas 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. Changes in fair value associated with 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.

	March 31, 2006
Financial instrument asset – current (1)	**$ 11,740**
Financial instrument liability – long term (2)	**(4,531)**
Net financial instrument asset	**$ 7,209**

(1) Financial instruments which will settle prior to April 1, 2007.

(2) Financial instruments which will settle after March 31, 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 March 31, 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 March 31, 2006	-	25,681	25,681
Amortization of the fair value of contracts as at March 31, 2006	(12,452)	-	(12,452)
Fair value of contracts entered into during the period	-	(6,020)	(6,020)
Unrealized gain on financial instruments	$ (32,905)	$ 40,114	$ 7,209
Realized loss on financial instruments for the period ended March 31, 2006			(2,264)
Net realized and unrealized gain on financial instruments for the period ended March 31, 2006			$ 4,945

Natural Gas commodity price hedges

At March 31, 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	30,000	$ 7.48	-	-	April – October 2006
AECO fixed price	30,000	$ 9.07	-	-	November 2006 – March 2007
AECO collar	5,000	-	$ 9.50	$ 11.00	November 2006 – March 2007
AECO collar	5,000	-	$ 9.00	$ 10.00	November 2006 – March 2007
AECO fixed price	37,500	$ 8.00	-	-	April 2007 – October 2007
AECO fixed price	22,500	$ 9.42	-	-	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 March 31, 2006 was a gain of $5.2 million. The change in fair value, a $25.7 million gain, and $12.5 million amortization of the deferred loss have been recorded in the consolidated statements of earnings. At March 31, 2006 a $6.0 million loss was recorded in the consolidated statement of earnings related to the fair value of financial contracts entered into after January 1, 2006. No deferred gains or losses were recorded related to these financial contracts.

The total realized loss recognized in net earnings for three months ended March 31, 2006 was $2.3 million (gain of $0.4 million for the three month period ended March 31, 2005).

12. Commitments

At March 31, 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 collar	5,000	-	$ 9.00	$ 12.50	April – October 2006
AECO fixed price	42,500	$ 7.64	-	-	April – October 2006
AECO collar	5,000	-	$ 9.00	$ 11.00	November 2006 – March 2007
AECO collar	5,000	-	$ 9.00	$ 10.00	November 2006 – March 2007
AECO collar	5,000	-	$ 8.50	$ 11.00	November 2006 – March 2007
AECO fixed price	32,500	$ 9.05	-	-	November 2006 – March 2007
AECO fixed price	37,500	$ 8.04	-	-	April 2007 – October 2007
AECO fixed price	17,500	$ 9.03	-	-	November 2007 – March 2008

During the three months ended March 31, 2006, the Trust entered into certain physical contracts to purchase natural gas from a third party at price collars that were equivalent to existing physical contracts to sell natural gas to the same third party. As a result of entering into these purchase contracts the Trust will collect premiums totaling $2.5 million over the term of the contracts; this amount has not been recorded in earnings for the current period. These contracts are as follows:

Type of contract	Volumes at AECO (GJ/d)	PET contract obligation	Price ($/GJ) Floor	Ceiling	Premium	Term
AECO collar	5,000	sell	$ 9.00	$ 12.50	-	April – October 2006
AECO collar	5,000	buy	$ 9.00	$ 12.50	$ 1,647,800	April – October 2006
AECO collar	5,000	sell	$ 8.00	$ 9.00	-	April – October 2006
AECO collar	5,000	buy	$ 8.00	$ 9.00	$ 813,200	April – October 2006
Total					$ 2,461,000	

13. Gas over bitumen issue

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 10 percent. The incremental royalties payable to the Crown would be limited to amounts recovered by a gas well operator through the reduced royalty.

At March 31, 2006 PET had recorded $48.0 million for cumulative gas over bitumen royalty adjustments received to that date.

14. Subsequent event

On April 6, 2006 the Trust issued $100 million aggregate principal amount of 6.25% convertible unsecured subordinated debentures.

Head office

500, 630 – 4th Avenue SW
Calgary, Alberta CANADA
T2P 0J9
PHONE 403 269.4400
FAX 403 269.4444
E-MAIL info@paramountenergy.com
WEB www.paramountenergy.com

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

Management

Clayton H. Riddell
Executive Chairman

Susan L. Riddell Rose
President and Chief Executive Officer

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
Vice President, Finance and Chief Financial Officer

Directors

Clayton H. Riddell(4)
Executive Chairman
Paramount Energy Operating Corp.

Chief Executive Officer
Paramount Resources Ltd.

Susan L. Riddell Rose(3)
President and Chief Executive Officer
Paramount Energy Operating Corp.

Karen A. Genoway(2)(4)(5)
Vice President, Land
Onyx Oil & Gas Ltd.

Donald J. Nelson(1)(2)(3)(4)(5)
President
Fairway Resources Inc.

John W. Peltier(1)(2)(3)(5)
President
Ipperwash Resources Ltd.

Howard R. Ward(1)(5)
Partner
International Energy Counsel LLP

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

Investor Relations

Susan M. Showers
Communications and Investor Relations Advisor

Auditors

KPMG LLP

Bankers

Bank of Montreal
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

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