NEWS RELEASE

PARAMOUNT ENERGY TRUST RELEASES YEAR END 2005 RESERVES AND FINANCIAL RESULTS

March 2006 Distribution Confirmed

Calgary, AB – March 14, 2006 (TSX – PMT.UN) - Paramount Energy Trust ("PET" or the "Trust") is pleased to release its unaudited fourth quarter and year-end 2005 results as well as its year end reserves information. Strong commodity prices, increased production, a significant acquisition of natural gas assets in Northeast Alberta and a measure of resolution to the gas over bitumen issue contributed to exceptional financial results in 2005.

PET is also pleased to confirm that its distribution to be paid on April 17, 2006 in respect of income received by PET for the month of March 2006, for Unitholders of record on March 31, 2006, will be $0.24 per Trust Unit. The ex-distribution date is March 29, 2006. The March distribution brings cumulative distributions paid since the inception of the Trust to $8.504 per Trust Unit.

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 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 Mar to Dec 2006 ($/GJ) (1)			
		$6.00	**$7.00**	**$8.00**	**$9.00**
Natural Gas Production	(MMcf/d)	159	159	159	159
Realized Gas Price	($/Mcf)	7.12	7.76	8.43	9.07
Cash Flow	($Million/Month)	21.0	23.3	25.8	28.1
Per Unit	($/Unit/Month)	0.247	0.275	0.304	0.332
Payout Ratio	(%)	99.1%	88.5%	79.9%	73.1%

(1) PET's weighted average hedge price on an average of 77,222 GJ/d for the period from April 1 to December 31, 2006 is $8.02/GJ using fixed prices and floor prices for collars. See "Hedging and Risk Management".

As a result of ongoing recent discussions with the Trust's auditors, investigating the methodology used to determine Trust Unit based compensation expense in general and administrative costs, PET is unable to release audited results today. However, the unaudited fourth quarter and year-end 2005 results and the results for prior periods do reflect a change in methodology to the binomial lattice method for valuing incentive rights and therefore the Trust expects to finalize its audited results in the near future.

Forward-Looking Information

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

Conference Call and Webcast

PET will be hosting a conference call and webcast at 2:30 p.m., Mountain Time, Wednesday March 15, 2006 to review this information. Interested parties are invited to take part in the conference call by dialing one of the following telephone numbers 10 minutes before the start time: **Toronto and area – 1-416-644-3426; outside Toronto – 1-866-250-4910.** For a replay of this call please dial: Toronto and area - 1-416-640-1917; outside Toronto – 1-877-289-8525, passcode 21180496# until March 22, 2006. To participate in the live webcast please visit **www.paramountenergy.com or** www.newswire.ca/en/webcast/index.cgi. The webcast will also be archived shortly following the presentation.

Paramount Energy Trust is a natural gas-focused Canadian energy trust. PET's Trust Units and Convertible Debentures are listed on the Toronto Stock Exchange under the symbol "PMT.UN", "PMT.DB" and "PMT.DB.A", respectively. Further information with respect to PET can be found at its website at www.paramountenergy.com.

The Toronto Stock Exchange has neither approved nor disapproved the information contained herein.

FOR ADDITIONAL INFORMATION, PLEASE CONTACT:

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FINANCIAL AND OPERATING HIGHLIGHTS (UNAUDITED)	**Three Months Ended December 31**			**Year Ended December 31**		
($CDN thousands, except volume and per Trust Unit amounts)	**2005**	**2004**	**% Change**	**2005**	**2004**	**% Change**
FINANCIAL						
Revenue before royalties	129,233	79,665	58	424,471	239,957	77
Cash flow (2)	78,200	56,521	38	260,218	143,592	81
Per Trust Unit (1) (2)	0.96	0.87	10	3.47	2.65	31
Net earnings (loss)	17,928	(29,696)	161	61,870	(17,544)	432
Per Trust Unit (1)	0.22	(0.46)	143	0.82	(0.32)	338
Cash distributions	58,990	39,135	51	205,032	121,314	69
Per Trust Unit (3)	0.72	0.60	20	2.72	2.18	25
Total assets	820,408	556,711	47	820,408	556,711	47
Net bank and other debt outstanding (7)	166,975	176,082	(5)	166,975	176,082	(5)
Convertible debentures	64,888	38,419	69	64,888	38,419	69
Total net debt	231,863	214,501	8	231,863	214,501	8
Unitholder's equity	394,643	264,451	49	394,643	264,451	49
Capital expenditures						
Exploration and development	11,402	2,247	407	59,896	28,891	107
Acquisitions, net	88	14,141	(99)	279,671	385,029	(27)
Other	718	11,118	(94)	1,267	11,169	(89)
Net capital expenditures	12,208	27,506	(55)	340,834	425,089	(20)
TRUST UNITS OUTSTANDING (thousands)						
End of period	82,482	65,327	26	82,482	65,327	26
Weighted average	81,625	65,082	27	74,998	54,188	38
Diluted	82,804	65,082	27	75,738	54,188	40
February 28, 2006	83,291			83,291		

FINANCIAL AND OPERATING HIGHLIGHTS CONTINUED	Three Months Ended December 31			Year Ended December 31		
	2005	2004	% Change	2005	2004	% Change
OPERATING						
Production						
Total natural gas (Bcf)	14.1	11.8	19	53.3	37.5	42
Daily average natural gas (MMcf/d)	153.7	128.0	20	146.0	102.5	42
Gas over bitumen deemed production (MMcf/d)	21.6	22.8	(5)	22.4	16.7	34
Average daily (actual and deemed – Mmcf/d)	175.3	150.8	16	168.4	119.2	41
Per Trust Unit (cubic feet/d/Unit) (1)	2.15	2.32	(7)	2.25	2.20	2
Exit rate (actual and deemed - MMcf/d) (8)	173.6	146.5	18	173.6	146.5	18
Per Trust Unit (cubic feet/d/Unit) (4)	2.10	2.24	(6)	2.10	2.24	(6)
Average prices						
Natural gas ($/Mcf), pre-hedging	10.18	6.74	51	8.30	6.51	27
Natural gas ($/Mcf), including hedging	9.14	6.78	35	7.97	6.40	25
RESERVES (Bcf)						
Proved (5) (6)	195.8	181.4	8	195.8	181.4	8
Proved plus probable (5) (6)	282.7	233.5	21	282.7	233.5	21
Per Trust Unit (Mcf/Unit) (4)	3.43	3.58	(4)	3.43	3.58	(4)
Estimated present value before tax ($ millions) (6)						
Proved	849.6	518.0	45	849.6	518.0	45
Proved plus probable	1,041.9	606.2	72	1,041.9	606.2	72
LAND (thousands of net acres)						
Total land holdings	2,420	1,917	26	2,420	1,917	26
Undeveloped land holdings	1,022	775	32	1,022	775	32
DRILLING						
Wells Drilled (gross/net)						
Gas	15/11.7	22/5.8	(32)/102	102/58.2	45/28.5	127/104
Dry	-	1/0.4	-/-	4/4.0	1/0.4	300/900
Total	15/11.7	23/6.2	(34)/89	106/62.2	46/28.9	130/115
Success Rate	100/100	96/94	4/6	96/93.6	98/99	(2)/(5)

(1) Based on weighted average Trust Units outstanding for the period.
(2) This is a non-GAAP measure; please refer to “Significant Accounting Policies and Non-GAAP Measures” included in Management’s Discussion and Analysis.
(3) Based on Trust Units outstanding at each cash distribution date.
(4) Based on Trust Units outstanding at period end.
(5) As evaluated by McDaniel & Associates Consultants Ltd. in accordance with National Instrument 51-101. See “Reserves” included in Management’s Discussion and Analysis.
(6) Discounted at 10% using consultant’s forecast pricing. Includes gas over bitumen royalty adjustments (2005 - $100.9 million, 2004 - $82.7 million) and gas over bitumen shut-in reserves (proved: 2005 – nil, 2004 – 12.0 Bcf and $8.7 million; proved plus probable: 2005 – 25.1 Bcf and $25.8 million, 2004 – 24.0 Bcf and $17.1 million).
(7) Net debt includes net working capital.
(8) Exit production is average production from last month in period.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Paramount Energy Trust's ("PET" or the "Trust") operating and unaudited financial results for the year ended December 31, 2005 as well as information and estimates concerning the Trust's future outlook based on currently available information. The financial results contained in this MD&A and annual consolidated financial statements are presented on an unaudited basis. The Trust's audited financial statements are expected to be finalized in the near future at which time they will be available at www.sedar.com. Readers are cautioned that the final audited statements may differ from those contained herein and that such differences may be material. This discussion should be read in conjunction with the Trust's consolidated financial statements for the years ended December 31, 2005 and 2004, together with accompanying notes. Readers are referred to the legal advisories regarding forward-looking information contained in the "Forward Looking Information" section of this MD&A. The date of this MD&A is March 13, 2006.

The Trust follows the "successful efforts" method of accounting for its petroleum and natural gas operations. This method, unlike the alternative "full cost accounting" method, usually generates a more conservative value for net earnings and cash flow as 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 results comparable to industry practice, geological and geophysical costs as well as surrendered leases and dry hole costs are added back to cash flow (see cash flow definition and reconciliation in the "Significant Accounting Policies and Non-GAAP measures" section of this MD&A).

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Chief Executive Officer, Susan Riddell Rose, and Chief Financial Officer, Cameron Sebastian, evaluated the effectiveness of PET's disclosure controls and procedures as of December 31, 2005 (the "Evaluation Date"), and concluded that PET's disclosure controls and procedures were effective: to ensure that information PET is required to disclose in its filings with the Securities and Exchange Commission under the Securities Exchange Act of 1934 (the "Exchange Act") is recorded, processed, summarized and reported, within the time periods specified in the Commission's rules and forms; and to ensure that information required to be disclosed by PET in the reports that it files under the Exchange Act is accumulated and communicated to PET's management, including its principal executive officer and principal financial officer, as appropriate to allow timely decisions regarding required disclosure.

CHANGES TO INTERNAL CONTROLS AND PROCEDURES FOR FINANCIAL REPORTING

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

CORPORATE GOVERNANCE

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

FOURTH QUARTER HIGHLIGHTS

- Production averaged 153.7 MMcf/d, a 20 percent increase from 128.0 MMcf/d for the fourth quarter of 2004. Cash flow reached a record $78.2 million for the quarter or $0.96 per Trust Unit, up 38 percent (10 percent on a per unit basis) from $56.5 million or $0.87 per Trust Unit in the fourth quarter of 2004.

- PET planned and began the execution of an $80 million winter capital program, the largest in the Trust's history, targeting 25-35 MMcf/d of natural gas production additions through drilling, completion, tie-in and seismic acquisition activities spread throughout the Trust's three core areas in Northeast Alberta.

- Distributions for the fourth quarter of 2005 totaled $0.72 per Trust Unit, paid on November 15, 2005, December 15, 2005 and January 16, 2006. PET's payout ratio for the quarter was 75.4% of its cash flow.

- In November 2005, the Alberta Energy and Utilities Board ("AEUB") issued its final bitumen conservation decision. Decision 2005-122 had minimal impact on the Trust, targeting one additional well, producing less than 50 Mcf/d net to PET, for shut-in effective January 1, 2006. Shut-in PET wells with a productive capacity of less than 200 Mcf/d net to PET were approved for production, for a net potential gain to the Trust's production of approximately 150 Mcf/d as a result of the decision.

- On December 23, 2005 PET announced our intent to acquire a private company ("AcquireCo") engaged in natural gas exploration and development in east-central Alberta, for an estimated cost including assumption of net debt of $92 million. This transaction closed as scheduled on February 16, 2006. Production from the AcquireCo assets is over 90% operated and measured approximately 9.5 MMcf/d as at the closing date. The AcquireCo properties are located southeast of PET's Athabasca core area, and offer over 50 shallow gas drilling and development prospects on 54,600 net acres of undeveloped year-round access lands.

ANNUAL HIGHLIGHTS

(CDN$ millions, except per Unit and volume data)	**2005**	2004	2003
Cash flow [1]	**$ 260.2**	$ 143.6	$ 126.4
Cash flow per Unit	**$ 3.47**	$ 2.65	$ 2.97
Net earnings (loss)	**$ 61.9**	$ (17.5)	$ 52.4
Distributions	**$ 205.0**	$ 121.3	$ 123.2
Distributions per Unit	**$ 2.72**	$ 2.18	$ 2.884
Payout ratio (%) [1]	**78.8%**	84.5%	97.5%
Production (Mcf/d) [2]			
Daily average production	**146,031**	102,472	85,574
Gas over bitumen deemed production	**22,413**	16,724	3,198
Total average daily (actual and deemed)	**168,444**	119,196	88,772

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

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

- On May 17, 2005 PET closed the acquisition of 100% shallow natural gas producing properties in Northeast Alberta (the "Northeast Alberta Assets") for $273.5 million. The Northeast Alberta Assets are in close proximity to the Trust's Northeast Alberta Core Areas but well outside the defined boundaries of the Alberta Energy and Utilities Board ("AEUB") gas over bitumen area of concern. The Northeast Alberta Assets added 87 Bcf of proved plus probable reserves and produced an average of 40.5 MMcf/d for the period from the date of acquisition.

- Concurrent with the acquisition of the Northeast Alberta Assets (the "Northeast Alberta Acquisition"), PET also entered into an agreement to sell on a bought deal basis, 9,500,000 subscription receipts at a price of $16.85 each for gross proceeds of approximately $160 million, and $100 million of five-year 6.25% convertible debentures (the "6.25% Debentures") to a syndicate of underwriters. The 6.25% Debentures are convertible into units of PET ("Trust Units") at a price of $19.35 per Trust Unit. The offering closed as scheduled on April 26, 2005. The Subscription Receipts were converted into Trust Units on the closing of the Northeast Alberta Acquisition.

- During the first quarter of 2005 PET completed the execution of a $40 million winter capital program in Northeast Alberta which included the drilling of 37 gas wells and over 150 recompletions distributed throughout the Trust's three core areas in the region. Approximately 18 MMcf/d of new production was brought onstream from the winter program by the end of the first quarter. PET followed up its successful winter program with a $15 million capital program targeting production and reserve additions from the year-round access assets in the Southern core area. Over the final three quarters of 2005 PET drilled 67 wells (27.8 net) with a 96% success rate, including participation in 43 wells (6.4) net in a non-operated coal bed methane project in the Craigmyle area of Southern Alberta.

- PET recorded average production of 146.0 MMcf/d, a 42% increase and a 3% increase per Trust Unit from 2004. Exceptional results from PET's winter capital program and rapid integration of the Northeast Alberta Assets into the Trust's existing operations were instrumental in achieving the production increase.

- Higher production and continued strength in natural gas prices led to record cash flows for PET in 2005. The Trust recorded cash flow of $260.2 million or $3.47 per Trust Unit for the year as compared to $143.6 million or $2.65 per Trust Unit for 2004.

- As a result of the gas over bitumen financial solution put in place by the Government of Alberta in January 2005, the accretive Northeast Alberta Acquisition, the success of PET's capital programs and continued strength in natural gas prices, PET raised monthly distributions by a total of 20 percent to $0.24 per Trust Unit during 2005. Distributions for 2005 of $2.72 per Trust Unit, combined with an increase in the closing market price of PET's Trust Units from $15.94 per Unit on December 31, 2004 to $22.17 per Unit on December 30, 2005, provided a total annual pre-tax return of 56% for Unitholders.

- In conjunction with PET's capital spending programs and significant acquisition activity, the Trust continued to maintain a strong balance sheet throughout 2005. PET's ratio of net debt, including convertible debentures, at December 31, 2005 to annualized fourth quarter cash flow measured 0.7 times.

OPERATIONS

Properties

The scale of PET's operations increased significantly during 2005, primarily due to the acquisition of theNortheast Alberta Assets in May of 2005. At the same time, the key attributes of PET's asset base remained unchanged. PET's assets are extremely focused technically, through the concentration on the production of shallow natural gas, and geographically, with over 90 per cent of PET's production coming from northeast Alberta. Virtually all of PET's properties feature well established, high working interest production and most are operated by PET. Production profiles are predictable due to the extensive production histories and the diversification of PET's production base. Relatively low operating costs and access to stable markets combine to deliver high field netbacks. PET has an extensive inventory of low cost opportunities for value creation which extends throughout the asset base, requiring modest capital expenditures to offset most of the annual natural production declines. Strategic infrastructure ownership throughout PET's asset base provides additional opportunities to add value through synergies and economies of scale.

The Trust's asset base is divided operationally into four core areas:

- **West Side** – includes assets west of Alberta Highway 63 which began with production from Devonian carbonate reservoirs;
- **East Side** – is comprised of assets east of Alberta Highway 63 (including Cold Lake) and production is mainly from Cretaceous clastic reservoirs;
- **Athabasca** – includes assets west of PET's original assets in the East Side and West Side and production is from both Cretaceous clastic reservoirs and Devonian carbonate reservoirs;
- **Southern** – includes assets in southern Alberta and Saskatchewan.

Production

Natural gas production by core area (MMcf/d)	**2005**	2004	2003
West Side	**45.3**	38.0	39.1
East Side (1)	**28.8**	34.5	46.2
Athabasca	**65.4**	24.9	-
Southern	**6.5**	5.1	0.3
Total	**146.0**	102.5	85.6

(1) As a result of the gas over bitumen regulatory issue described in this MD&A, PET had an average of 22.4 MMcf/d of deemed production during 2005 attributable to properties in the East Side core area.

Production volumes increased 42 percent to 146.0 MMcf/d in 2005 compared to 102.5 MMcf/d in 2004. The increase in production was attributed to the Northeast Alberta acquisition which closed in May 2005, a full year of production from the 2004 acquisitions of Cavell Energy Corporation ("Cavell acquisition") and assets in the Athabasca area of northeast Alberta ("Athabasca Acquisition"), as well as the results of the 2005 capital expenditure program. The Northeast Alberta Acquisition increased average 2005 gas production by 25.4 MMcf/d, while the Trust's 2005 winter capital program added approximately 18 MMcf/d of production above the base case forecast in PET's independent reserve report.

In 2005, five properties located within the Trust's four core areas accounted for 44 percent of the Trust's production with the largest single property accounting for 14 percent of the total production. This diversification of production minimizes the risk that operating problems at a specific property will materially impact the Trust.

Capital Expenditures

($ thousands except where noted)	**2005**	2004	2003
Exploration and development expenditures	**52,214**	27,767	8,213
Undeveloped land acquisitions	**7,682**	1,124	114
Acquisitions	**285,956**	417,779	32,252
Dispositions	**(9,285)**	(32,750)	-
Oil and gas properties acquired from Paramount Resources Ltd.	**-**	-	269,162
Other	**1,267**	11,169	757
Total capital expenditures and net acquisitions	**337,834**	425,089	310,498

Total capital expenditures including net property and corporate acquisitions aggregated to $337.8 million in 2005 ($425.1 million in 2004). Of the total, $52.2 million was incurred on drilling and completions, geological, geophysical and facilities expenditures, $7.7 million was in respect of undeveloped land acquisitions, with the remaining $277.9 million attributable to net property and corporate acquisitions including $20.7 million of the Devon acquisition allocated to undeveloped acreage.

PET's exploration and development expenditures were concentrated in its three winter-only access core areas in northeast Alberta, with a $40 million capital program conducted in the first quarter of 2005. The program targeted both significant low-cost production additions through shallow drilling, completion and tie-in activities, efficiencies in the Trust's operating cost structure through facilities optimization and consolidation projects and seismic acquisition for future prospect definition.

Following up on the success of PET's winter capital program, the Trust initiated a $15 million summer capital expenditure program focused on exploiting drilling opportunities in its year-round access areas.

Total acquisitions of $286.0 million in 2005 reflect primarily the Northeast Alberta Acquisition, as well as consolidating acquisitions in the Birch/Tar and Wabasca areas of northeast Alberta which totaled 1.3 MMcf/d of natural gas production and 0.9 MMcf/d of gas over bitumen shut-in production.

PET's exploration and development expenditures for 2005 were funded entirely by cash flow in excess of distributions of $55.2 million. Undeveloped land acquisition and net property and corporate acquisitions were funded indirectly through excess cash flow, the Trust's credit facility and through the issuance of 9.5 million Trust Units and $100.0 million in convertible debentures in May 2005.

The Board of Directors of Paramount Energy Operating Corp., PET's administrator, has approved a budget for exploration and development capital expenditures of up to $100 million for 2006, of which approximately $3 million in preliminary costs were incurred in 2005.

Drilling

	2005		2004		2003	
	Gross	**Net**	Gross	Net	Gross	Net
Gas	**102**	**58.2**	45	28.5	16	11.4
Service	**-**	**-**	-	-	1	0.5
Dry	**4**	**4.0**	1	0.4	-	-
Total	**106**	**62.2**	46	28.9	17	11.9
Success rate (%)	**96**	**94**	98	99	100	100

PET drilled 106 gross wells in 2005, as compared to 46 in 2004. Drilling activity was spread throughout the Trust's three core areas in northeast Alberta in the first quarter of 2005, with 37 (30.8 net) wells drilled with a 90% success rate. Through the last nine months of 2005 the Trust drilled 21 (19.9 net) operated wells and 3 (1.5) non-operated wells in the Southern core area, achieving a 95% net success rate. PET also participated in 43 wells (6.4 net) as part of its non-operated coalbed methane project in the Craigmyle area of southern Alberta.

Reserves

PET's complete NI 51-101 reserves disclosure as at December 31, 2005 including underlying assumptions regarding commodity prices, expenses and other factors and reconciliation of reserves on a Net Interest Basis (working interest less royalties payable), is available in the Trust's Annual Information filed on www.sedar.com.

The reserves data set out below (the "Reserves Data") is based upon an evaluation by McDaniel and Associates Consultants Ltd. ("McDaniel") with an effective date of December 31, 2005 contained in a report of McDaniel dated March 8, 2006 (the "McDaniel Report"). The Reserves Data summarizes the natural gas reserves of the Trust and the net present values of future net revenue for these reserves using McDaniel forecast prices and costs. The oil and natural gas liquids reserves of PET are immaterial.

Natural gas reserves as at December 31 (MMcf)	**2005**	2004	2003
Proved			
Developed producing	**179,976**	162,597	115,218
Developed non-producing	**6,860**	3,647	2,826
Shut-in gas over bitumen reserves[(1)]	**-**	11,988	4,567
Undeveloped	**9,006**	3,181	656
Total Proved	**195,842**	181,413	123,267
Probable			
Developed producing, developed non-producing and undeveloped	**61,777**	40,162	16,318
Shut-in gas over bitumen reserves [(1)]	**25,065**	11,969	9,202
Total probable	**86,842**	52,131	25,520
Total proved & probable	**282,684**	233,544	148,787
Trust Units outstanding at December 31 (millions)	**82.5**	65.3	44.6
Total proved & probable per Trust Unit (Mcf/Unit)	**3.43**	3.58	3.33

(1) The McDaniel Report assumes that the shut-in gas over bitumen reserves are probable, that the reserves return to production after 10 years of shut-in and that such production is subject to an incremental 10 percent gross overriding royalty pursuant to the amended Natural Gas Royalty Regulation ("Royalty Regulation"). In 2004, 50 percent of the shut-in gas over bitumen reserves were classified as proved.

The net present values of future net revenues for PET's reserves, using McDaniel forecast prices and costs at a 10% discount rate are presented in the table below. For income tax purposes PET is able to and intends to claim a deduction for all amounts paid or payable to the Unitholders and then allocate remaining taxable income, if any, to the Unitholders. Accordingly, no income tax amounts have been reported in this reserves data.

Net present values of reserves as at December 31 ($thousands) (Discounted at 10%)	**2005**	2004	2003
Proved			
Developed producing	**727,775**	426,559	228,989
Developed non-producing	**6,989**	(4,227)	9,663
Gas over bitumen royalty adjustments	**100,863**	82,706	-
Shut-in Gas over Bitumen Reserves[(1)]	**(1,308)**	8,710	-
Undeveloped	**15,363**	4,265	416
Total Proved	**849,682**	518,013	239,068
Probable			
Developed producing, developed non-producing and undeveloped	**166,441**	79,826	34,847
Shut-in gas over bitumen reserves [(1)]	**25,785**	8,383	-
Total probable	**192,226**	88,209	34,847
Total proved & probable	**1,041,908**	606,223	273,915
Trust Units outstanding at December 31 (millions)	**82.5**	65.3	44.6
Total proved & probable per Trust Unit ($/Unit)	**12.63**	9.28	6.14

(1) The McDaniel Report assumes that the shut-in gas over bitumen reserves are probable but the future abandonment and reclamation liability associated with the wells is proved, that the reserves return to production after 10 years of shut-in and that such production is subject to an incremental 10 percent gross overriding royalty pursuant to the amended Natural Gas Royalty Regulation. In 2004, 50 percent of the shut-in gas over bitumen reserves were classified as proved.

The following table sets forth a reconciliation of the changes in reserves for the year ended December 31, 2005 from the opening balance on December 31, 2004 derived from the McDaniel Reports at those dates, using McDaniel forecast prices. PET's reserves include both working interests and royalty interests.

Reserves reconciliation (Bcf)	**Proved**	Probable	Proved & Probable
December 31, 2004	181.4	52.1	233.5
Discoveries and extensions	18.4	4.8	23.2
Technical revisions	(5.5)	(4.8)	(10.3)
Reclassification of shut-in gas over bitumen reserves from proved to probable (1)	(11.7)	11.7	-
Acquisitions, net of dispositions	66.5	23.0	89.5
Production	(53.3)	-	(53.3)
December 31, 2005	**195.8**	**86.8**	**282.6**

(1) In 2005 the gas over bitumen shut-in reserves were recategorized as probable from 50 percent proved and 50 percent probable in 2004, as the Phase 3 Final Hearing under the AEUB GB 2003-28 process was concluded and the final decision rendered in November 2005.

According to the McDaniel Report, over 91% of the Trust's proved reserves are developed producing reserves. The McDaniel report identifies minimal future capital expenditures to realize the estimated production potential of the reserves identified: $31 million for the proved reserves and $7 million for the probable reserves, $14 million of which are specified for 2006. Internally, the Trust has a significant inventory of opportunities which exceeds the forecast future capital expenditures recognized in the reserve report, including the opportunities currently being pursued in the Trust's 2006 exploration and development capital program.

Finding, Development and Acquisition Costs

2005 Capital Expenditures ($millions)	Proved	Proved & Probable
Exploration and development	52.2	52.2
Undeveloped land	7.7	7.7
Acquisitions	286.0	286.0
Dispositions	(9.3)	(9.3)
Total net oil and gas capital expenditures	336.6	336.6
Less increase in net book value of undeveloped land	(11.4)	(11.4)
Add increase in future development capital	21.5	27.0
2005 FD&A net capital expenditures (1)	346.7	352.2
Reserve Additions (Bcf)		
Increase in year-end reserves before reclassification (2)	26.1	49.1
Reclassification of gas over bitumen reserves	(11.7)	-
Increase in year-end reserves	14.4	49.1
Annual production	53.3	53.3
2005 reserve additions	79.7	102.4
Finding, development and acquisition costs ($/Mcf) (3)	$4.35	$3.44

(1) FD&A is finding, development and acquisition costs.
(2) Increase in year end reserves is before change in classification of shut-in gas over bitumen reserves to probable from 50% proved and 50% probable in the previous year.
(3) F&D costs for proved reserves are calculated on increase in year-end reserves before reclassification of gas over bitumen shut-in reserves to probable from 50 percent proved and 50 percent probable in 2004.

The Trust's finding and development costs on a proved and probable basis were $3.44 per Mcf for 2005, as compared to $3.09 per Mcf for 2004. The higher F&D costs in 2005 are primarily the result of a general increase in the cost of field services from the previous year as well as the cost of the acquisition of the Northeast Alberta Assets.

Land

Land inventory	2005 Net acres	2005 Average working interest	2004 Net acres	2004 Average working interest
Developed	**1,398,194**	**74.0%**	1,141,468	81.5%
Undeveloped	**1,021,976**	**74.8%**	775,140	85.8%
Total	**2,420,170**	**74.4%**	1,916,608	83.2%

PET's undeveloped acreage position increased by 32 percent in 2005. At 7.0 net undeveloped acres per producing Mcf, PET has one of the most extensive inventories of undeveloped land relative to its production base in the energy trust sector. The Northeast Alberta acquisition added 339,733 net acres of undeveloped land.

The Trust's undeveloped acreage in the East Side core area includes approximately 225,000 net acres inside the gas over bitumen area of concern. While development of this acreage is restricted in certain formations, there are numerous other prospective zones in the region. The mineral rights for leases with shut-in production are continued indefinitely under Section 8-1-h of the *Mines and Minerals Act* (Alberta) until resolution of the gas over bitumen issue.

PET estimates the fair value of its undeveloped acreage to be $83 million at December 31, 2005 (December 31, 2004 - $55 million).

Asset Retirement Obligation and Salvage Value of Tangible Equipment

PET engaged Prevent Technologies Ltd., an independent evaluator, to estimate its total future asset retirement obligation 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 $94.3 million as at December 31, 2005 based on an undiscounted total future liability of $190.2 million. As at December 31, 2005, the estimated undiscounted net salvage value of the Trust's gas plants, compressors and facilities was estimated at $130.3 million ($62.0 million discounted at 10%). The McDaniel Report includes an undiscounted amount of $75.3 million ($33.9 million discounted at 10%) with respect to expected future well abandonment costs for our proved and probable reserves. Incorporating the estimates from Prevent Technologies, PET has assets in excess of the liabilities not considered by McDaniel's in the Reserve Report of $15.4 million on an undiscounted basis ($1.6 million discounted at 10%).

Gas Over Bitumen Issue

The Alberta Energy and Utilities Board ("AEUB") issued General Bulletin 2003-28 ("GB 2003-28") and Interim Shut-In Order 03-001 on July 22, 2003, establishing a process to identify gas production in the Wabiskaw-McMurray formations which may be posing an unacceptable risk to the potential bitumen resource. The AEUB considers that gas production in pressure communication with associated potentially recoverable bitumen places future bitumen recovery at an unacceptable risk.

Following the completion of a Regional Geological Study by the AEUB and an interim hearing held in March 2004 the AEUB ordered the shut-in, effective July 1, 2004, of Wabiskaw-McMurray natural gas production in northeast Alberta totaling approximately 123 MMcf/d. As of July 1, 2004, PET had shut-in wells producing approximately 17.2 MMcf/d of sales gas pursuant to Decision 2004-045 and Interim Shut-In Orders 04-001 and 04-002 including 4.5 MMcf/d from the zones shut-in on September 1, 2003 pursuant to the GB 2003-28 and Interim Shut-In Order 03-001. An additional 0.2 MMcf/d was shut-in on September 1, 2004 pursuant to Decision 2004-064 and Interim Shut-In Order 04-003 related to wells in the Chard and Leismer areas.

On October 4, 2004 the Government of Alberta enacted amendments to the Royalty Regulation with respect to natural gas, 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 Regulation, sets out the details of the gas over bitumen financial solution. In July 2005, further amendments were enacted to the Royalty Regulation with respect to natural gas, implementing a positive correction to the royalty calculation formula to provide a $0.05 per Mcf reduction in the effective operating costs adjustment. This effectively increases the net royalty adjustment by $0.025 per Mcf of deemed production and is retroactive to the date of shut-in. The revised formula for calculation of the royalty reduction provided in the Royalty Regulation is:

0.5 x ((deemed production volume x 0.80) x (Alberta Gas Reference Price - $0.3791/GJ))

Through this formula, operating costs are effectively deemed to be $0.40 Per Mcf, royalties are deemed to be 20%, the deemed production is assigned the Alberta Gas Reference Price, which includes a transportation component and the entire formula is assigned an arbitrary 50% reduction factor. The components of netbacks for the gas over bitumen shut-in reserves can be derived as below:

Gas over Bitumen Royalty Adjustment Netback

($ per Mcf)	**2005**	2004	2003 (1)
Average deemed volume (MMcf/d) (2)	**22.4**	16.7	9.6
Gas price	**8.30**	6.28	5.20
Royalties	**(1.66)**	(1.26)	(1.04)
Operating costs	**(0.40)**	(0.40)	(0.40)
Arbitrary 50% reduction factor	**(3.12)**	(2.31)	(1.88)
Gas over bitumen royalty adjustment netback	**3.12**	2.31	1.88

(1) From September 1, 2003 to December 31, 2003

(2) Represents 20.5 MMcf/d of shut-in production (2004 – 14.6 MMcf/d, 2003 – 7.4 MMcf/d) and 1.9 MMcf/d of wells denied production under AEUB ID 99-1 (2004 and 2003 – 2.1 MMcf/d)

All actual gas over bitumen royalty adjustments received in 2004, including retroactive payments for shut-in during the period September 1 through December 31, 2003, were recorded as an adjusting item for cash flow from operations in 2004.

The Trust's net deemed production volume for purposes of the royalty adjustment was 22.4 MMcf/d in 2005. Deemed production represents all PET natural gas production shut-in or denied production pursuant to a Decision Report, corresponding AEUB Order or General Bulletin, 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.

During 2005, the Trust received $30.6 million in gas over bitumen royalty adjustments, a substantial increase from the $11.2 million received in 2004. With the interim shut-in orders effective July 1 and September 1, 2004, the increase in the 2005 gas over bitumen royalty adjustment was related to the full year effect of shut-in as well as increased gas prices as the royalty adjustment is calculated using the actual Alberta Gas Reference Price each month. 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 December 31, 2005 to $41.8 million. Royalty adjustments, although not included in earnings, are recorded as a component of funds from operations and as such are considered distributable income.

The Phase 3 Final Hearing with respect to the AEUB's bitumen conservation requirements commenced on June 14, 2005 and ended on August 12, 2005. PET, an active participant in the hearing, filed detailed evidence supporting the resumption of production from six gas pools representing approximately 8.5 MMcf/d of production the Trust currently has shut-in pursuant to AEUB Orders. PET also reiterated to the AEUB its continued objection to all zones that have been shut-in as a result of the interim hearing based on the new evidence that the Trust has submitted.

On November 11, 2005 PET advised that the AEUB issued Decision 2005-122 (the "Decision") regarding the Phase 3 Final Hearing. The Decision had minimal impact on the Trust, targeting one additional well, producing less than 50 Mcf/d net to PET, for shut-in effective January 1, 2006. Shut-in PET wells with a productive capacity of less than 200 Mcf/d net to PET were approved for production, for a net potential gain to the Trust's production of approximately 150 Mcf/d as a result of the decision.

With the AEUB GB 2003-28 process now complete, PET will continue to focus on converting its shut-in natural gas assets back into producing assets. While the Trust is receiving partial relief for its lost cash flow in the form of monthly royalty reductions, PET still owns the shut-in reserves and they are more valuable if returned to production. PET will continue to monitor new information as there is potential that future field evidence from actual Steam Assisted Gravity Drainage ("SAGD") projects will provide support to PET's technical position. The Trust will also continue its active involvement in technical solution initiatives.

Future AEUB reviews will be project specific in nature and will be focused on either bitumen production project approval or gas production approval. Technical solutions such as flue gas injection, gas cap repressurization with air, low pressure pump technology, THAI and VAPEX technology as well as other research initiatives that may not yet have been identified are now the focus of PET and others in industry to reduce the perceived risk gas production may pose to potentially recoverable bitumen resources. PET is also diligent in the monitoring of all future proposed SAGD projects in our operating areas as associated gas production and contamination from SAGD operations is a serious concern for all owners of shut-in gas reserves.

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.

MARKETING

Natural Gas Prices

	2005	2004	2003
Reference prices			
AECO Monthly Index ($/Mcf)	**$ 8.50**	$ 6.54	$ 6.70
Alberta Gas Reference Price ($/Mcf)	**$ 8.30**	$ 6.28	$ 6.13
Average PET prices			
Natural gas, before hedging ($/Mcf)	**$ 8.30**	$ 6.51	$ 6.39
% AECO, before hedging	**98%**	100%	95%
% Alberta Gas Reference Price, before hedging	**100%**	104%	104%
Natural gas, after hedging (1) ($/Mcf)	**$ 7.97**	$ 6.40	$ 6.72
% AECO, after hedging	**94%**	98%	100%
% Alberta Gas Reference Price, after hedging	**96%**	102%	110%

(1) Hedging includes financial forward contracts and options.

U.S. natural gas prices are typically referenced off NYMEX at the Henry Hub, Louisiana while western Canada natural gas prices are referenced to the AECO Hub in Alberta. AECO Monthly Index Hub prices increased sharply to average $8.50 per Mcf in 2005 as compared to $6.54 per Mcf for 2004, a 30 percent change. This was largely driven by a significant increase in natural gas prices in September and the fourth quarter of 2005 following disruption of Gulf of Mexico natural gas production as a result of Hurricanes Katrina and Rita. AECO Monthly Index prices in the fourth quarter of 2005 averaged $11.69 per Mcf as compared to $7.09 per Mcf in 2004, an increase of 65 percent.

The Alberta Gas Reference Price is the monthly weighted average of an intra-Alberta consumers' price and an ex-Alberta border price, reduced by allowances for transporting and marketing gas. The Alberta Gas Reference Price is used to calculate Alberta Gas Crown Royalties. The Alberta Gas Reference Price increased 32 percent from $6.28 per Mcf in 2004 to $8.30 per Mcf in 2005.

PET's natural gas price, prior to hedging transactions, increased by 27 percent to $8.30 per Mcf in 2005 from $6.51 per Mcf in 2004. PET's average realized gas price after hedging transactions was $7.97 per Mcf and $6.40 per Mcf in 2005 and 2004 respectively. The difference between the Trust's natural gas price before and after hedging can be attributed to fixed-price financial contracts entered into by PET in order to lock in attractive returns on the Northeast Alberta Acquisition and provide distribution stability for our Unitholders.

Hedging and Risk Management

PET's commodity price risk management activities are conducted in consultation with the Board of Directors of the Administrator of the Trust with the objective of using a proactive and opportunistic approach to hedging in order to maximize distributable income while managing price risk rather than a routine portfolio approach. A number of market analysis tools are used in an attempt to identify perceived anomalies or trends in natural gas markets. Hedging may be used to ensure or enhance the economics related to significant acquisitions. The Trust mitigates exposure to credit risk associated with these risk management contracts by only entering into financial hedging transactions with financially sound, credit-worthy counterparties.

At December 31, 2005 the Trust had entered into financial hedge arrangements as follows:

Volumes at AECO (Gigajoules/day)("GJ/d")	Price ($/GJ)	Term
65,000 GJ/d	$ 8.40	January 2006 – March 2006
20,000 GJ/d	$ 8.01	April 2006 – October 2006

Had these contracts been settled on December 31, 2005, using forward prices in effect at that time the mark-to-market settlement payment by PET would have totaled $22.6 million. As the Trust follows hedge accounting for these instruments this amount has not been recorded in the financial statements. The January, February and March hedges have now settled for a net realized loss of $2.1 million and the mark-to-market settlement on the remaining financial contracts using prices in effect on March 13, 2006 would have been a receipt to PET of $7.1 million. This equates to a net realized and projected mark-to-market gain on the hedges in place on December 31, 2005 of $5.0 million as at March 13, 2006.

At December 31, 2005 PET had entered into forward physical gas sales arrangements as follows:

	Price ($/GJ)			
Volumes at AECO (Gigajoules/day)("GJ/d")	Fixed	Floor	Ceiling	**Term**
65,000 GJ/d	$8.50	-	-	January 2006 – March 2006
25,000 GJ/d	$8.03	-	-	April 2006 – October 2006
5,000 GJ/d	-	$9.00	$12.50	April 2006 – October 2006

The January, February and March physical sales have now settled for a net realized loss of $2.1 million and the mark-to-market settlement on the remaining forward physical sales contracts using prices in effect on March 13, 2006 would have been a receipt to PET of $11.7 million. This equates to a net realized and projected mark-to-market gain on the physical forward sales in place on December 31, 2005 of $9.2 million as at March 13, 2006.

The Trust's hedging and physical sales portfolio has changed significantly since December 31, 2005. Total financial hedge arrangements and physical sales contracts outstanding as of March 13, 2006 are as follows:

Volumes at AECO

Type of Contract	GJ/d	Price ($/GJ) Fixed	Floor	Ceiling	Term
Financial	27,500 GJ/d	$7.54	-	-	April 2006 – October 2006
Physical	42,500 GJ/d	$7.64	-	-	April 2006 – October 2006
Physical	5,000 GJ/d	-	$9.00	$12.50	April 2006 – October 2006
Period Total	**75,000**		**$7.70(1)**		**April 2006 – October 2006**
Financial	30,000 GJ/d	$9.025	-	-	November 2006 – March 2007
Financial	5,000 GJ/d	-	$9.50	$11.00	November 2006 – March 2007
Financial	5,000 GJ/d	-	$9.00	$10.00	November 2006 – March 2007
Physical	30,000 GJ/d	$9.035	-	-	November 2006 – March 2007
Physical	5,000 GJ/d	-	$9.00	$11.00	November 2006 – March 2007
Physical	5,000 GJ/d	-	$9.00	$10.00	November 2006 – March 2007
Physical	5,000 GJ/d	-	$8.50	$11.00	November 2006 – March 2007
Period Total	**85,000**		**$9.0212(1)**		**November 2006 – March 2007**
Financial	27,500 GJ/d	$7.94	-	-	April 2007 – October 2007
Physical	27,500 GJ/d	$7.91	-	-	April 2007 – October 2007
Period Total	**55,000**		**$7.9230**		**April 2007 – October 2007**
Financial	12,500 GJ/d	$9.272	-	-	November 2007 – March 2008
Physical	12,500 GJ/d	$9.031	-	-	November 2007 – March 2008
Period Total	**25,000**		**9.1515**		**November 2007 – March 2008**

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

The mark-to-market settlement on the outstanding financial hedges and physical forward sales contracts using prices in effect at the close of market on March 13, 2006, assuming the floor price for the collars is a fixed price, is a receipt of $24.9 million. In addition to the January through March contracts which have settled as described above, PET has settled or collected premiums for other contracts for an additional $3.3 million since year end 2005.

FINANCIAL RESULTS

Revenue

($ thousands)	**2005**	2004	2003
Oil and natural gas revenue, before hedging	**442,505**	244,303	199,488
Hedging receipts (payments) (1)	**(17,764)**	(4,346)	10,318
Total revenue	**424,741**	239,957	209,806

(1) Hedging receipts (payments) includes settlement of financial forward contracts and options.

Oil and natural gas revenue in 2005 was $424.7 million, representing a 77 percent increase from $240.0 million in 2004. Revenue growth was achieved via the 43 percent increase in natural gas volumes and the 25 percent increase in realized prices after hedging adjustments in 2005 as compared to the prior year.

Operating Netbacks

The components of operating netbacks are shown below:

Netback

($ per Mcf)	**2005**	2004	2003
Gas price	**$ 7.97**	$ 6.40	$ 6.72
Royalties	**(1.66)**	(1.11)	(1.22)
Operating costs	**(1.20)**	(1.03)	(0.89)
Transportation costs	**(0.26)**	(0.26)	(0.28)
Netback	**$ 4.85**	$ 4.00	$ 4.33

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

Total aggregate operating costs increased by $25.2 million (65 percent) to $64.0 million in 2005 from $38.8 million in 2004, primarily as a result of the 43 percent increase in average production related to the Northeast Alberta acquisition. On a unit of production basis, operating costs increased by 17 percent to $1.20 per Mcf in 2005 from $1.03 per Mcf in 2004. Unit costs increased as a result of ongoing fixed costs for facilities with lost production from the gas over bitumen shut-ins and an overall industry trend towards increasing operating costs resulting from competitive conditions and a shortage of oilfield services and manpower.

PET pays Crown, freehold and overriding royalties that are dependent upon production volumes, commodity prices, location and age of producing wells and type of production. Gas Crown royalties are reduced by Gas Cost Allowance ("GCA") deductions. The GCA deductions are based on processing fees and allowable capital costs incurred at a property and are in accordance with Crown royalty regulations. Royalty income received is included in revenue. The effective royalty rate applicable to the Trust in 2005 was 20.9 percent (2004 – 17.3 percent) or $1.66 per Mcf (2004 - $1.11 per Mcf). The increase in royalty rate over 2004 was primarily a result of higher reference natural gas prices and PET's realized natural gas prices that were lower than the Alberta Gas Reference Price, upon which Alberta Crown Royalties are calculated, in September and the fourth quarter of 2005. Also a higher production rate per well in the Northeast Alberta Assets, as compared to the Trust's base assets, also contributed to higher royalties as a percentage of revenue.

Costs to transport gas from the plant gate to the commercial market sales point are not reflected as an operating cost but rather are recorded as transportation costs for the product. Total transportation costs increased by 40 percent to $13.7 million ($0.26 per Mcf) in 2004 from $9.8 million ($0.26 per Mcf) in 2004 as a result of the increased production.

General and Administrative Expense

	2005		2004		2003	
	$000's	$/Mcf	$000's	$/Mcf	$000's	$/Mcf
Cash general & administrative	**10,807**	**0.20**	7,119	0.19	3,980	0.13
Gas over bitumen costs	**1,000**	**0.02**	1,160	0.03	696	0.02
Trust Unit-based compensation	**1,993**	**0.04**	2,374	0.08	-	-
Total general & administrative	**13,800**	**0.26**	9,493	0.30	4,676	0.15

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

G&A expenses, net of overhead recoveries on operated properties, increased to $13.8 million from $9.5 million in 2004 but decreased on a unit-of-production basis from $0.30 per Mcf in 2004 to $0.26 per Mcf in 2005. The 2005 total included $1.0 million in legal and consulting expenditures directly related to the AEUB gas over bitumen issue ($1.2 million – 2004). Included in total G&A expenses are $2.0 million in 2005 related to Trust Unit-based compensation costs charged to earnings under new accounting rules adopted in 2004. The Trust Unit-based compensation costs for 2004 were $2.4 million. The Trust expects 2006 G&A costs excluding non-cash G&A to remain relatively flat in 2006.

Interest Expense

Interest expense increased to $8.0 million in 2005 from $4.8 million in 2004 as a result of a higher monthly average debt balance following the Northeast Alberta acquisition, in addition to a slightly higher interest rate as a result of the increase in the Bank of Canada lending rate during 2005. On a unit-of-production basis, interest expenses were $0.055 per Mcf in 2005 as compared to $0.047 per Mcf in 2004.

In 2005, $6.3 million of interest on the convertible debentures was expensed as compared to $1.4 million in 2004. The increase was due to the issuance of $100 million of the 6.25% Debentures in April 2005, and a full year of interest expense on the 8% convertible debentures (the "8% Debentures") issued in August 2004.

Depletion, Depreciation and Accretion

PET's 2005 depletion, depreciation and accretion (DD&A) rate decreased to $2.80 per Mcf from $2.90 per Mcf in 2004, primarily due to a lower depletable base for the Saskatchewan properties due to the impairment charge recorded on that cost centre in 2004. The Trust calculates its depletion factor using proved reserves and production; as there is no production associated with the shut-in gas over bitumen reserves no depletion expense is recorded on the related costs. Gas over bitumen deemed production is not included in the DD&A calculation. The DD&A rate includes accretion expense on the asset retirement obligation of $3.6 million in 2005 as compared to $2.1 million in 2004. The increase in accretion is a function of both higher production volumes and a significant increase in the asset retirement obligation in 2005 as compared to 2004. An upward revision of the estimated cost of individual well abandonment operations driven by a general increase in the cost of services in the oil and gas industry coupled with the Trust's larger well base in 2005, gave rise to the increase in the asset retirement obligation from $34.1 million at December 31, 2004 to $94.3 million at December 31, 2005. (See Note 10 to the Consolidated Financial Statements.)

Depletion, Depreciation and Accretion

($ thousands except where noted)	**2005**	2004	2003
Depletion expense	**145,469**	106,777	61,436
Accretion of asset retirement obligation	**3,617**	2,090	1,239
Total	**149,086**	108,867	62,675
Per Unit ($/Mcf)	**2.80**	2.90	2.01

At year end 2005, property, plant and equipment costs included undeveloped land of $83.9 million (2004 - $72.5 million) currently not subject to depletion and $32.5 million (2004 - $35.4 million) of costs related to shut-in gas over bitumen reserves which are not being depleted due to the non-producing status of the wells in the affected properties .

Income Taxes

The Trust and its principal operating entities are taxable entities under the *Income Tax Act* (Canada) and are taxable only on income that is not distributed or distributable to the Unitholders. As the Trust distributes all of its taxable income to the Unitholders pursuant to its Trust Indenture and meets the requirements of the *Income Tax Act* (Canada) applicable to the Trust, no provision for income taxes has been made relative to the Trust. The Administrator has no tax balances.

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

Impairment Test

PET performs impairment tests annually or as economic events dictate. An impairment loss is recognized when the carrying amount of a property or project is greater than the sum of the expected future cash flows (undiscounted and without interest charges) from that property or project. The amount of the impairment loss is calculated as the difference between the carrying amount and the present value of estimated future cash flows.

At December 31, 2005 the sum of the expected future cash flows for each separate property group within the Trust exceeds the carrying amount of its associated property, plant and equipment. As such, no impairment loss was recorded in 2005.

At December 31, 2004 PET recorded a writedown of property, plant and equipment of $65.4 million related primarily to its Saskatchewan properties.

Net Earnings and Cash Flow

Cash flow totaled $260.2 million ($3.47 per Trust unit) for the year ended December 31, 2005 as compared to $143.6 million ($2.65 per Trust unit) for the year ended December 31, 2004, a 31 percent increase on a per Trust Unit basis. The 81 percent increase in cash flow in 2005 is primarily the result of the 42 percent increase in production combined with the 25 percent increase in realized gas prices, with higher gas over bitumen royalty adjustments also factoring into the increased cash flows from 2004 levels.

Cash Flow Reconciliation

	2005		2004	
	$ millions	($/Mcf)	$ millions	($/Mcf)
Production volume (Bcf)		**53.3**		37.5
Revenue	**424.7**	**7.97**	240.0	6.40
Royalties	**(88.7)**	**(1.66)**	(41.7)	(1.11)
Operating costs	**(64.0)**	**(1.20)**	(38.8)	(1.03)
Transportation costs	**(13.7)**	**(0.26)**	(9.8)	(0.26)
Operating netback from production	**258.3**	**4.85**	149.7	4.00
Gas over bitumen royalty adjustments	**30.6**	**0.57**	11.2	0.30
Lease rentals	**(3.0)**	**(0.06)**	(2.1)	(0.06)
General and administrative [1]	**(10.8)**	**(0.20)**	(7.1)	(0.19)
Gas over bitumen costs	**(1.0)**	**(0.02)**	(1.2)	(0.03)
Interest on bank and other debt	**(8.0)**	**(0.15)**	(4.8)	(0.13)
Interest on convertible debentures [1]	**(5.6)**	**(0.10)**	(1.3)	(0.03)
Capital taxes	**(0.3)**	**(0.01)**	(0.8)	(0.02)
Cash flow [1]	**260.2**	**4.88**	143.6	3.83

[1] Excluding non-cash items

Net earnings measured $61.9 million or $0.82 per Trust Unit in 2005 as compared to a loss of $17.5 million or $0.32 per Trust Unit in 2004. Higher revenue, a lower depletion rate and the absence of impairment losses in 2005 were the primary factors in the increase in net earnings over 2004.

Summary Fourth Quarter Information

Fourth Quarter Information	**Three months ended December 31**		
$ thousands except per Trust Unit, per Mcf and percent amounts	**2005**	2004	% change
Daily production volumes (Mcf/d)	**153,715**	127,959	20
Natural gas revenues	**129,233**	79,665	62
Realized natural gas price	**$ 9.14**	$ 6.78	35
Royalties	**33,918**	15,342	121
Royalties as a percentage of revenues	**26.2%**	19.3%	36
Operating expenses	**16,837**	10,849	55
Operating expenses per Mcf	**$ 1.19**	$ 0.92	29
General and administrative expenses	**3,349**	1,671	100
General and administrative expenses per Mcf	**$ 0.24**	$ 0.14	71
Cash flow	**78,200**	56,521	38
Cash flow per Trust Unit	**$ 0.96**	$ 0.87	10
Net earnings (loss)	**17,928**	(29,696)	160
Net earnings (loss) per Trust Unit	**$ 0.22**	$ (0.46)	148
Capital expenditures – exploration and development	**11,402**	13,899	(18)

In comparing the fourth quarter of 2005 with the same period in 2004:

- Production increased 20 percent due primarily to the Northeast Alberta Acquisition and a successful winter capital program in 2005.
- Natural gas prices were 35 percent higher in the fourth quarter of 2005 as a result of higher AECO daily spot and monthly index prices compared to the three months ended December 31, 2004.
- The Trust’s royalty rate increased to 26% of revenues as realized natural gas prices were lower than the Alberta Reference Price due to a number of fixed-price gas contracts entered into by PET to lock in attractive returns on the Northeast Alberta Acquisition.

- Operating costs increased 29% to $1.19 per Mcf as a result of generally higher costs for field services and supplies as compared to the prior year and additional maintenance required on the Northeast Alberta Acquisition facilities.
- These factors combined to generate a 38% increase in cash flow to $78.2 million from $56.5 million for the fourth quarter of 2004.
- Net earnings increased 155 percent to $17.9 million due to higher cash flow and a lower depletion rate; 2004 results were also impacted by an after-tax writedown of $39 million pertaining to the Trust's Saskatchewan cost centre.

LIQUIDITY, CAPITALIZATION AND FINANCIAL RESOURCES

Capitalization and Financial Resources

$ thousands except per Trust Unit and percent amounts	**2005**	2004
Bank and other debt	**168,106**	171,698
Convertible debentures	**64,888**	38,419
Working capital deficiency (surplus)	**(1,131)**	4,384
Net debt	**231,863**	214,501
Trust Units outstanding (000's)	**82,482**	65,327
Market price at end of period	**22.17**	15.88
Market value of Trust Units	**1,828,626**	1,037,392
Total capitalization [(1)]	**2,060,489**	1,251,893
Net debt as a percent of total capitalization	**11.3%**	17.1%
Cash flow	**260,218**	143,592
Net debt to cash flow ratio	**0.9**	1.5

[(1)] These are Non-GAAP measures; see "Significant Accounting Policies and Non-GAAP Measures" in this MD&A.

At December 31, 2005, PET had bank debt outstanding of $168.1 million compared to $171.7 million at December 31, 2004 and $64.9 million in convertible debentures outstanding versus $38.4 million at December 31, 2004. The increase in convertible debentures from 2004 levels is a result of the $100 million offering of 6.25% Debentures closed in April 2005 as partial funding for the Northeast Alberta Acquisition, less $73.2 million of debenture conversions during the year.

After financing the AcquireCo acquisition in February 2006 through PET's existing credit facilities, bank and other debt is currently approximately $263 million.

PET has a revolving credit facility with a syndicate of six Canadian Chartered Banks. As at the date of this MD&A the revolving credit facility had a borrowing base of $310 million. The facility consists of a demand loan of $300 million and a working capital facility of $10 million. In addition to amounts outstanding under the facility, PET has outstanding letters of credit in the amount of $2.87 million. Collateral for the credit facility is provided by a floating-charge debenture covering all existing and after acquired property of the Trust as well as unconditional full liability guarantees from all subsidiaries in respect of amounts borrowed under the facility.

Advances under the 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 average interest rate at December 31, 2005 was 4.17%.

December 31, 2005 net debt to total capitalization was 11.3 percent (17.1 percent in 2004) and net debt to 2005 cash flow was 0.9 times (1.5 times in 2004).

The Trust expects that its distributions and capital expenditure program for 2006 will be funded by cash flow with PET's Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan") enhancing PET's balance sheet.

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

		Payments Due by Period			
Contractual Obligations ($millions)	Total	Less than 1 year	1-3 years	4-5 years	After 5 years
Bank and other debt	$ 168.1	$ 162.4	$ 0.8	$ 0.9	$ 4.0
Convertible debentures	$ 64.9	-	-	$ 64.9	-
Total contractual obligations	$ 233.0	$ 162.4	$ 0.8	$ 65.8	$ 4.0

Convertible Debentures

The Trust's 6.25% 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 6.25% 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 twelve months ended December 31, 2005, $42.1 million of 6.25% Debentures were converted, resulting in the issuance of 2,175,380 Trust Units.

The Trust's 8% Debentures mature on September 30, 2009, bear interest at 8.00% 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% 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 twelve months ended December 31, 2005, $31.1 million of 8% Debentures were converted, resulting in the issuance of 2,187,642 Trust Units.

At December 31, 2005, PET had $7.4 million of 8% Debentures outstanding with a fair market value of $11.6 million and $57.9 million of 6.25% Debentures outstanding with a fair market value of $66.6 million.

Unitholders' Equity

PET's total capitalization was $2,060.5 million at December 31, 2005 with the market value of the Trust Units representing 89 percent of total capitalization. During 2005, the market price of the Trust Units ranged from $15.88 to $23.44 with an average daily trading volume of 191,000 Units.

PET implemented an industry-leading DRIP Plan for eligible Unitholders of the Trust in February 2004. The DRIP Plan provides Unitholders with the opportunity to reinvest monthly cash distributions to acquire additional Trust Units at 94 percent of the Treasury Purchase Price, which is defined as the daily volume weighted average trading price of the Trust Units for the 10 trading days immediately proceeding a distribution payment date. As well, subject to thresholds and restrictions described in the DRIP Plan, it contains a provision for the purchase of additional Trust Units with optional cash payments of up to $100,000 per participant per fiscal year of PET at the same 6 percent discount to the Treasury Purchase Price. No additional commissions, service or brokerage fees will be charged to the Unitholder for these transactions. In 2005 the DRIP Plan resulted in an additional 2,853,601 Trust Units (2004 – 632,829 Trust Units) being issued at an average price of $17.34 (2004 - $12.93) raising a total of $49.5 million (2004 - $8.2 million).

On December 31, 2005 there were 82.5 million Trust Units outstanding. Trust Units were issued during 2005 as follows:

- On April 26, 2005 PET closed an equity financing issuing 9.5 million Trust Units at $16.85 per Unit for net proceeds of $152.1 million.
- During 2005, 0.4 million Trust Units were issued by way of exercised incentive rights for net proceeds of $3.8 million.
- During 2005, 2.9 million Trust Units were issued through the DRIP Plan for net proceeds of $49.5 million.
- In 2005, 4.4 million Trust Units were issued through the conversion of $72.3 million of convertible debentures into Trust Units.

CASH DISTRIBUTIONS

PET declared cash distributions of $205.0 million ($2.72 per Unit) in 2005 representing 79 percent of 2005 cash flow, bringing total cumulative distributions since inception to $449.5 million ($7.784 per Trust Unit). In 2004, declared cash distributions were $121.3 million ($2.18 per Trust Unit), representing 84 percent of cash flow. The Trust's focus on distribution sustainability has resulted in a reduction in the payout ratio from 2004 to 2005, as PET now reserves a higher portion of our cash flow for financing capital expenditures and acquisitions. The Trust estimates a payout ratio for 2006 of approximately 85 percent of cash flow, given current forward natural gas prices and the Trust's estimates for 2006 production and cash flow.

Taxation of 2005 Cash Distributions

Cash distributions are comprised of a return of capital portion (tax deferred) and a return on capital portion (taxable). For cash distributions received or receivable by a Canadian resident, outside of a registered pension or retirement plan in the 2005 taxation year, the split between the two is 95.4 percent taxable and 4.6 percent tax deferred.

PET, in consultation with its tax advisors, is of the view that the 2005 distributions paid to non-corporate Unitholders who are U.S. residents are "Qualified Dividends" for U.S. tax purposes. With respect to distributions paid in 2005, 86.30 percent would be reported as qualified dividends and 13.70 percent would be reported as non-taxable return of capital for U.S. residents. PET performed an earnings and profits calculation for U.S. tax purposes in order to make this determination. U.S. residents should contact their own advisors with respect to their specific circumstances.

2005 Distributions by Month
($ per Trust Unit)

Payment Date	Canadian Taxable Amount	Canadian Tax Deferred Amount (Return of Capital)	Total Distribution
February 15, 2005	$ 0.210	$ 0.010	$ 0.220
March 15, 2005	0.210	0.010	0.220
April 15, 2005	0.210	0.010	0.220
May 16, 2005	0.210	0.010	0.220
June 15, 2005	0.210	0.010	0.220
July 15, 2005	0.210	0.010	0.220
August 15, 2005	0.210	0.010	0.220
September 15, 2005	0.210	0.010	0.220
October 17, 2005	0.229	0.011	0.240
November 15, 2005	0.229	0.011	0.240
December 15, 2005	0.229	0.011	0.240
January 16, 2006	0.229	0.011	0.240
Total	**$ 2.596**	**$ 0.124**	**$ 2.720** [1]
Percent	**95.4%**	**4.6%**	**100.0%**

[1] Total is based upon cash distributions paid and payable during 2005

2006 Cash Distributions

PET has declared three consecutive distributions of $0.24 per month per Trust Unit in 2006 and estimates that this level of monthly distributions will be sustainable for the foreseeable future, based upon the Trust's current hedges and the forward market for natural gas prices, however distributions are subject to change as dictated by actual conditions.

SUMMARY OF QUARTERLY RESULTS

	Three Months Ended			
(thousands of dollars, except per Unit amounts)	**Dec 31, 2005**	**Sept 30, 2005**	**June 30, 2005**	**Mar 31, 2005**
Natural gas revenues before royalties	$ 129,233	$ 118,928	$ 100,234	$ 76,346
Net earnings	$ 17,928	$ 30,432	$ 11,357	$ 2,153
Net earnings per Unit - basic	$ 0.22	$ 0.39	$ 0.15	$ 0.03
- diluted	$ 0.22	$ 0.38	$ 0.15	$ 0.03

	Three Months Ended			
(thousands of dollars, except per Unit amounts)	**Dec 31, 2004**	**Sept 30, 2004**	**June 30, 2004**	**Mar 31, 2004**
Natural gas revenues before royalties	$ 79,665	$ 59,156	$ 49,904	$ 51,232
Net earnings (loss)	$ (29,696)	$ 4,813	$ 5,147	$ 2,192
Net earnings (loss) per Unit - basic	$ (0.46)	$ 0.08	$ 0.11	$ 0.05
- diluted	$ (0.46)	$ 0.08	$ 0.11	$ 0.05

Natural gas revenues have trended steadily higher over the eight quarters shown above. 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.

The increased net earnings in the second, third and fourth quarters of 2005 are due to higher production and natural gas prices, 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 cost centre.

2006 OUTLOOK AND SENSITIVITIES

Based on current commodity prices, PET's hedging portfolio, production levels and exploration and development capital expenditure budget, following are PET's current estimates of key measures for 2006:

		2005	2006E (1)(2)
Natural Gas Production	MMcf/d	146.0	156.2
Gas Prices			
AECO Monthly Index	$/GJ	$ 8.50	$ 8.50
PET Realized	$/Mcf	$ 7.97	$ 8.73
Monthly Cash Flow	$/Unit/Month	$ 0.29	$ 0.31
Monthly Average Distributions	$/Unit/Month	$ 0.23	$ 0.24
Payout Ratio	%	78.8%	72.0%
Ending Debt to Cash Flow Ratio (3)	Times	0.9	0.8

(1) Cash flow and payout ratio are non-GAAP terms; please refer to "Significant Accounting Policies and Non-GAAP Measures" in this MD&A

(2) Amounts are based on PET's 2006 budget and may not reflect the current market for forward natural gas prices or PET's current hedging position.

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

Below is a table that shows sensitivities of PET's 2006 cash flow to operational changes and changes in the business environment:

		Impact on Cash Flow per Trust Unit	
	Change	**Annual**	**Monthly**
Business Environment			
Price per Mcf of natural gas (PET Avg.)	$ 0.25/Mcf	0.07	0.006
Interest rate on debt	1%	0.03	0.003
Operational			
Gas production volume	5 MMcf/d	0.10	0.008
Operating costs	$ 0.10/Mcf	0.07	0.006
Cash G&A expenses	$ 0.10/Mcf	0.07	0.006

These sensitivities assume operating costs of $1.20 per Mcf, cash general and administrative expenses of $0.19 per Mcf, and an interest rate on long term bank debt of 4.65 percent. Cash general and administrative expenses are equal to general and administrative expenses before stock-based compensation.

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, unlike the alternative "full cost accounting" method, generates a more conservative value for net earnings and cash flow as 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 results 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") and cash flow per Trust Unit 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:

(thousands of dollars, except per Trust Unit amounts)	For the year ended December 31 2005	2004
Cash provided by operating activities	$ 237,349	$ 136,441
Exploration costs [(1)]	16,850	774
Settlement of asset retirement obligation	660	-
Changes in non-cash operating working capital	5,359	6,377
Cash flow	$ 260,218	$ 143,592
Cash flow per Trust Unit [(2)]	$ 3.47	$ 2.65

(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 on Trust Units 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 from operating activities, 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.

CRITICAL ACCOUNTING ESTIMATES

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

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

Accounting for petroleum and natural gas operations

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

Reserve estimates

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

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

Impairment of petroleum and natural gas properties

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

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

Asset retirement obligations

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

CHANGE IN ACCOUNTING POLICY

On January 1, 2005 the Trust retroactively applied the fair value based method of accounting for Trust Unit incentive rights ("Incentive Rights"). Prior to 2005, PET accounted for Incentive Rights using the intrinsic method, whereby the excess of the market trading price of the Trust Units at the date of the financial statements over the exercise price of the Incentive Rights was recorded as compensation expense over the vesting period. Under the fair value based method of accounting, compensation expense was recorded based on the fair value of the Trust Unit-based compensation at the date of grant using a modified Black-Scholes option pricing model for the first nine months of 2005. On October 1, 2005, the Trust retroactively adopted the binomial lattice option pricing model as an alternative to the modified Black Scholes model. PET believes the binomial lattice model provides a more accurate valuation than the modified Black Scholes model, particularly for unit incentive rights that feature a declining exercise price, such as those granted by PET.

Under the fair value method, compensation expense associated with Incentive Rights is recognized in earnings over the vesting period. Consideration received upon the exercise of the Rights together with the amount previously recognized in contributed surplus is recorded as an increase in Unitholders' capital. The Trust has not incorporated an estimated forfeiture rate for Rights that will not vest, and accounts for actual forfeitures as they occur.

As a result of the change in accounting policy, PET restated previously reported annual and quarterly net earnings for 2004 as follows:

	Three months ended			
(thousands of dollars, except per Unit amounts)	Dec 31, 2004	Sep 30, 2004	Jun 30, 2004	Mar 31, 2004
Reported net earnings (loss) before change in accounting policy	$ (30,484)	$ 2,890	$ 5,029	$ 1,902
Effect of change in accounting policy	$ 788	$ 1,923	$ 118	$ 290
Restated net earnings (loss)	$ (29,696)	$ 4,813	$ 5,147	$ 2,192
Net earnings (loss) per Unit, as reported – basic & diluted	$ (0.47)	$ 0.05	$ 0.11	$ 0.04
Net earnings (loss) per Unit, as restated – basic & diluted	$ (0.46)	$ 0.08	$ 0.11	$ 0.05

NEW ACCOUNTING POLICIES

Financial Instruments

Canadian Institute of Chartered Accountants ("CICA") Handbook section 3860 "Financial Instruments" requires that fixed-amount contractual obligations that can be settled by issuing a variable number of equity instruments be classified as liabilities. The convertible debentures previously issued by the Trust have characteristics that meet the noted criteria and therefore we have retroactively accounted for these instruments as debt, with a portion representing the value of the equity conversion feature in equity and reflected interest costs as interest expense in the statement of earnings.

Variable Interest Entities ("VIEs")

In June 2003, the CICA issued Accounting Guideline 15 "Consolidation of Variable Interest Entities" ("AcG-15"). AcG-15 defines VIEs as entities in which either: the equity at risk is not sufficient to permit that entity to finance its activities without additional financial support from other parties or equity investors lack voting control, an obligation to absorb expected losses or the right to receive expected residual returns. AcG-15 harmonizes Canadian and U.S. GAAP and provides guidance for companies consolidating VIEs in which they are the primary beneficiary. The guideline is effective for all annual and interim periods beginning on or after November 1, 2004. We have performed a review of entities in which PET has an interest and have determined that we do not have any variable interest entities at this time.

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.

Reserve Estimates

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

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

Cyclical and Seasonal Impact on Industry

The Trust's operational results and financial condition will be dependent on the prices received for natural gas production. Natural gas prices have fluctuated widely during recent years and are determined by supply and demand factors including weather and general economic conditions, as well as conditions in other oil and natural gas producing regions. Any decline in natural gas prices could have an adverse effect on the Trust's financial condition.

Operational Matters

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

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

Expansion of Operations

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

Acquisitions

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

Debt Service

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

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

Depletion of Reserves

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

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

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

There can be no assurance that PET will be successful in developing or acquiring additional reserves on terms that meet the Trust's investment objectives.

Net Asset Value

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

Insurance Risk

Exploration for natural gas and the production of natural gas are hazardous undertakings. Further, natural disasters, operator error or other occurrences can result in oil spills, blowouts, cratering, fires, equipment failure and loss of well control, which can injure or kill people, damage or destroy wells and production facilities and damage other property and the environment. Losses and liabilities arising from such events could significantly reduce the Trust's revenues or increase costs and have a material adverse effect on the Trust's operations or financial condition.
PET may be unable to obtain insurance against these risks at premium levels that justify its purchase. Further, insurance may be unavailable or any insurance we may obtain may be insufficient to provide full coverage. The occurrence of a significant event that is not fully insured could have a material adverse effect on PET's financial position and reduce or eliminate distributions to Unitholders.

Additional Financing

PET's primary source of bank financing is a demand credit facility with a syndicate of Canadian chartered banks in the amount of $310 million. The credit facility is presently due March 31, 2006. PET expects that the facility will be extended at that date. If the facility is not extended the Trust will need to find alternative sources of financing. If alternative sources of financing are not available, or are more expensive than the current credit facility, PET may be unable to effectively operate our business or pay distributions to Unitholders.

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

Hedging

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

- buying a price floor under which the Trust will receive a minimum price for natural gas production;
- buying a collar under which the Trust will receive a price within a specified price range for natural gas production;
- entering into fixed price contract for natural gas production;
- entering into contracts to fix the basis differential between natural gas markets; and
- entering into contracts to fix the price differential between light and heavy oil.

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

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

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

Non-resident Ownership of Trust Units

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

Accounting Write-Downs as a Result of GAAP

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

Income Tax Legislation

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

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

The Administrator intends that PET will continue to qualify as a mutual fund trust for purposes of the Income Tax Act (Canada).

Renegotiation or Termination of Contracts

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

Competitive Conditions

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

Environmental Considerations

Compliance with health, safety and environmental laws and regulations could materially increase the Trust's costs. PET will incur substantial capital and operating costs to comply with increasingly complex laws and regulations covering the protection of the environment and human health and safety. These include costs to reduce certain types of air emissions and discharges and to remediate contamination at various facilities and third party sites where the Trust's products or wastes will be handled or disposed.
PET are subject to statutory strict liability in respect of losses or damages suffered as a result of pollution caused by spills or discharges of petroleum from petroleum facilities covered by any of the Trust's licenses. As a result, anyone who suffers losses or damages as a result of pollution caused by PET's operations can claim compensation without needing to demonstrate that the damage is due to any fault on the Trust's part.

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

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

For example, the Canadian government has adopted the 1997 Kyoto Protocol to the United Nations Framework Convention on Climate Change. As a result, new requirements and regulations may be implemented which would require PET to incur significant costs to comply. In addition, increasingly strict environmental requirements affect product specifications and operational practices. Future expenditures to meet such specifications could have a material adverse effect on the Trust's operations or financial condition. Any abandonment costs PET incur will reduce distributions to Unitholders.

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

Government Regulation Risk

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

Commodity Price, Foreign Exchange and Interest Rate Risk

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

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

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

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

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

Nature of Trust Units

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

FORWARD-LOOKING INFORMATION

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

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

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

- the quantity and recoverability of PET's reserves;
- the timing and amount of future production;
- prices for natural gas produced;
- operating and other costs;
- business strategies and plans of management;
- supply and demand for natural gas;
- expectations regarding PET's access to capital to fund its acquisition exploration and development activities add to its reserves through acquisitions as well as through 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 at www.sedar.com or from the Trust’s website at www.paramountenergy.com.

Paramount Energy Trust
Consolidated Balance Sheets
(Unaudited)

As at	**December 31, 2005**	**December 31, 2004**
($ thousands)		**(restated, note 2)**
Assets		
Current assets		
Accounts receivable	$ 57,837	$ 30,355
Other assets (note 3)	5,269	1,773
Property, plant and equipment (notes 4 and 5)	728,173	494,885
Goodwill (note 4)	29,129	29,698
	$ 820,408	$ 556,711
Liabilities		
Current liabilities		
Accounts payable and accrued liabilities	$ 36,910	$ 21,674
Distributions payable	19,796	13,065
Bank and other debt (note 6)	168,106	171,698
	224,812	206,437
Gas over bitumen royalty adjustments (note 14)	41,789	11,200
Asset retirement obligations (notes 5 and 10)	94,276	34,116
Convertible debentures (note 7)	64,888	38,419
Future income taxes (note 13)	-	2,088
Unitholders' Equity		
Unitholders' capital (note 8)	769,210	495,862
Equity component of convertible debentures	490	-
Contributed surplus (note 2)	4,052	4,536
Deficit	(379,109)	(235,947)
	394,643	264,451
	$ 820,408	$ 556,711

See accompanying notes
Basis of Presentation: note 1
Commitments and contingency: notes 11,12 and 14
Subsequent event: note 15

Paramount Energy Trust
Consolidated Statements of Earnings (Loss) and Deficit
(Unaudited)

	Year Ended December 31 2005	2004
($ thousands except per unit amounts)		**(restated, note 2)**
Revenue		
Oil and natural gas	$ 424,741	$ 239,957
Royalties	(88,746)	(41,661)
	335,995	198,296
Expenses		
Operating	64,016	38,818
Transportation	13,688	9,782
Exploration	19,808	2,867
General and administrative	12,800	9,493
Gas over bitumen (note 14)	1,000	1,160
Interest on bank and other debt (note 6)	7,963	4,817
Interest on convertible debentures (note 7)	6,314	1,410
Write-down of property, plant and equipment (note 5)	-	65,384
Depletion, depreciation and accretion (notes 5 and 10)	149,735	108,867
	275,324	242,598
Earnings (Loss) before Income Taxes	60,671	(44,302)
Future income tax reduction (Note 13)	(1,519)	(27,610)
Capital taxes	320	852
	(1,199)	(26,758)
Net Earnings (Loss)	61,870	(17,544)
Deficit, beginning of year, as previously reported	(238,670)	(93,953)
Retroactive effect of change in accounting policies (note 2)	2,723	(3,136)
Deficit, beginning of year, as restated	(235,947)	(97,089)
Distributions	(205,032)	(121,314)
Deficit, end of year	$ (379,109)	$ (235,947)
Earnings (loss) per Trust Unit (note 1(d))		
Basic & diluted	$ 0.82	$ (0.32)
Distributions per Trust Unit	$ 2.72	$ 2.18

See accompanying notes

Paramount Energy Trust
Consolidated Statements of Cash Flows
(Unaudited)

	Year Ended December 31	
	2005	**2004**
($ thousands)		**(restated, note 2)**
Cash provided by (used for)		
Operating activities		
Net earnings (loss)	$ 61,870	$ (17,544)
Items not involving cash		
Depletion, depreciation and accretion	149,735	108,867
Trust Unit-based compensation (note 9)	1,993	2,374
Write-down of property, plant and equipment	-	65,384
Future income tax reduction	(1,519)	(27,610)
Amortization of other assets	700	147
Gas over bitumen royalty adjustments (note 14)	30,589	11,200
Expenditures on site restoration and reclamation	(660)	-
Change in non-cash working capital	(5,359)	(6,377)
	237,349	136,441
Financing activities		
Issue of Trust Units	171,052	142,364
Distributions to Unitholders	(176,071)	(116,680)
Issue of convertible debentures	96,000	46,080
Change in bank and other debt	(3,592)	116,134
Change in non-cash working capital and other assets	5,172	5,263
	92,561	193,161
Investing activities		
Acquisition of investment	(1,243)	-
Disposal of investment	594	-
Acquisition of properties	(287,223)	(350,274)
Proceeds on sale of property and equipment	6,285	32,750
Exploration and development expenditures	(43,046)	(28,891)
Change in non-cash working capital	(5,277)	16,813
	(329,910)	(329,602)
Change in cash	-	-
Cash, beginning of period	-	-
Cash, end of period	$ -	$ -
Interest paid	$ 15,128	$ 4,649
Taxes paid	$ 457	$ -

See Accompanying Notes

1. BASIS OF PRESENTATION AND ACCOUNTING POLICIES

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

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

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

a) **Principles of Consolidation** The consolidated financial statements include the accounts of the Trust and its subsidiaries, all of which are wholly-owned.

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

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

   The net amount at which petroleum and natural gas costs on an operational field are carried is subject to a cost-recovery test annually or as economic events dictate. An impairment loss is recognized when the carrying amount of the asset is greater than the sum of the expected future cash flows (undiscounted and without interest charges). The amount of the impairment loss is calculated as the difference between the carrying amount and the discounted present value of estimated future cash flows. The carrying values of capital assets including the costs of acquiring proved and probable reserves are subject to uncertainty associated with the quantity of oil and gas reserves, future production rates, commodity prices and other factors.

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

   The Trust's corporate assets are recorded at cost and are depreciated on a straight line basis at rates ranging from 5 percent to 33 percent.

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

d) **Per Unit Information** Basic earnings (loss) per Trust Unit are calculated using the weighted average number of Trust Units outstanding (2005 - 74,997,667; 2004 – 54,187,525). PET uses the treasury stock method where only dilutive instruments where market price exceeds exercise price impact the diluted calculations. In computing diluted earnings (loss) per Trust Unit 740,066 net Trust Units were added to the weighted average number of Trust Units outstanding during the year ended December 31, 2005 (2004 – nil net Units) for the dilutive effect of incentive rights. In computing diluted earnings (loss) per Trust Unit 175,000 Incentive Rights, as well as 2,992,558 potentially issuable Trust Units through the 6.25% convertible debentures, were excluded as the exercise and conversion prices were out of the money at December 31, 2005. For 2004 all units were excluded from the diluted earnings (loss) per Trust Unit calculation as PET recorded a loss for the period.

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

f) **Financial Instruments** Financial instruments may be utilized by PET to manage its exposure to commodity price fluctuations, foreign currency and interest rates.

PET uses forward, futures and swap contracts to manage its exposure to commodity price fluctuations. The net receipts or payments arising from these contracts are recognized in earnings as a component of natural gas revenue during the same period as the corresponding hedged position.

PET formally documents, specifically defining relationships between hedging instruments and hedged items, its risk management objective and strategy for undertaking various hedge transactions. This process includes linking all derivatives to specific assets and liabilities on the balance sheet or to specific firm commitments or forecasted transactions. Both at the hedge's inception and on an ongoing basis PET also formally assesses whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair value or cash flows of hedged items.

g) **Income Taxes** PET, and its principal operating entity POT, are taxable entities under the *Income Tax Act* (Canada) and are taxable only on income that is not distributed or distributable to the Unitholders. As the Trust distributes all of its taxable income to the Unitholders pursuant to the PET Trust Indenture and meets the requirements of the *Income Tax Act* (Canada) applicable to the Trust, no provision for income taxes has been made in these consolidated financial statements related to the operations of the Trust. The Administrator has no tax balances.

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

h) **Incentive Rights Plans** PET has a Unit Incentive Plan and a Bonus Rights Plan as described in Note 9. Incentive Rights granted under the Unit Incentive Plan are accounted for using the fair-value based method. Upon the exercise of the rights, consideration received, together with the amount previously recognized in contributed surplus, is recorded as an increase to Unitholders' capital.

During 2005 the Trust adopted a change in accounting policy for the Unit Incentive Plan, as described in note 2.

Rights granted under the Bonus Rights Plan are charged to earnings in the period they are granted, and a corresponding liability is recognized for any unexercised bonus rights. This liability is adjusted at each balance sheet date as a result of changes in the market trading price of the Trust Units.

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

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

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

k) **Goodwill** Goodwill is recorded upon a corporate acquisition when the total purchase price exceeds the fair value of the net identifiable assets and liabilities of the acquired company. The goodwill balance is not amortized but instead is assessed for impairment annually or more frequently, if necessary. Impairment is determined based on the fair value of the reporting entity compared to the carrying value of the reporting entity. Any impairment will be charged to earnings in the period in which the fair value of the reporting entity is below the carrying value.

l) **Gas Over Bitumen Royalty Adjustments** Royalty adjustments received are recorded as a liability as PET cannot determine if, when or to what extent the royalty adjustment may be repayable through incremental royalties if and when gas production recommences. Royalty adjustments will be included in earnings when such determination can be made (see note 14).

2. CHANGE IN ACCOUNTING POLICY

Trust Unit-based compensation

On January 1, 2005 the Trust retroactively applied the fair value based method of accounting for Trust Unit incentive rights ("Incentive Rights"). Prior to 2005, PET accounted for Incentive Rights using the intrinsic method, whereby the excess of the market trading price of the Trust Units at the date of the financial statements over the exercise price of the Incentive Rights was recorded as compensation expense over the vesting period. Under the fair value based method of accounting, compensation expense was recorded based on the fair value of the Trust Unit-based compensation at the date of grant using the binomial lattice option pricing model.

Under the fair value method, compensation expense associated with Incentive Rights is recognized in earnings over the vesting period. Consideration received upon the exercise of the Rights together with the amount previously recognized in contributed surplus is recorded as an increase in Unitholders' capital. The Trust has not incorporated an estimated forfeiture rate for Incentive Rights that will not vest, and accounts for actual forfeitures as they occur.

Retroactive application of the fair value method using the binomial lattice model resulted in a decrease in opening deficit and an increase in opening contributed surplus for 2004 of $0.4 million. Further, reported Trust Unit compensation expense for the year ended December 31, 2004 decreased by $3.1 million to $2.4 million with a corresponding decrease in contributed surplus and net loss.

A reconciliation of contributed surplus resulting from adoption of the new policy is provided below:

Balance, as at January 1, 2004, as previously reported	$ 2,740
Adoption of fair value method	396
Balance, as at January 1, 2004, as restated	3,136
Trust Unit-based compensation expense, as previously reported	5,493
Reduction in Trust Unit-based compensation expense upon restatement	(3,119)
Transfer to Unitholders' capital on exercise of Incentive Rights	(974)
Balance, as at December 31, 2004, as restated	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

3. OTHER ASSETS

	December 31, 2005	December 31, 2004
Convertible debenture issue costs	$ 2,269	$ 1,773
Investment	3,000	-
	$ 5,269	$ 1,773

Convertible debenture issue costs are amortized to earnings over the life of the related debentures and any umamortized amounts are reclassified to Unitholders' capital as and when debentures are converted to Trust Units. As at December 31, 2005, accumulated amortization of $0.6 million (2004 - nil) has been recognized in these 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. ACQUISITIONS

a) On May 17, 2005 the Trust closed the acquisition of producing natural gas properties in Northeast Alberta for an aggregate purchase price of $273.5 million.

Property, plant and equipment acquired	$	286,768
Asset retirement obligations		(13,267)
Net purchase price	$	273,501

b) On July 16, 2004 PET acquired Cavell Energy Corporation ("Cavell") for consideration of 6,931,633 Trust Units with an ascribed value of $78.7 million plus $30 million of cash and acquisition costs, net of stock option proceeds, of $8.0 million. Cavell was a public oil and gas exploration and production company active in Western Canada. This transaction has been accounted for using the purchase method with the allocation of the purchase price as follows:

Property, plant and equipment	$	156,822
Goodwill		29,698
Working capital deficiency		(5,572)
Bank debt		(28,729)
Asset retirement obligation		(5,847)
Future income taxes		(29,698)
	$	116,674
Consideration		
Cash	$	30,000
Trust units issued		78,674
Acquisition costs		8,000
	$	116,674

Goodwill recognized on the purchase of Cavell has been reduced by $0.5 million in 2005 to reflect adjustments to certain income tax balances of Cavell at the closing date of the acquisition.

5. PROPERTY, PLANT AND EQUIPMENT

	December 31, 2005	December 31, 2004
Petroleum and natural gas properties	$ 1,274,639	$ 954,351
Asset retirement costs	87,990	30,787
Corporate assets	16,020	14,754
	1,378,649	999,892
Accumulated depletion and depreciation	(650,476)	(505,007)
	$ 728,173	$ 494,885

Property, plant and equipment costs include undeveloped land of $83.9 million (2004 - $72.5 million) and $32.5 million of costs (2004 - $35.4 million) related to shut-in gas over bitumen reserves (Note 14), which are not being depleted due to the non-producing status of the related wells.

At December 31, 2004 the Trust recorded a write-down to property, plant and equipment in the amount of $65.4 million as a result of prescribed successful efforts impairment tests related primarily to the Trust's Saskatchewan properties.

Corporate assets include $10.5 million related to the acquisition of PET's head-office building and related leasehold improvements acquired in November 2004.

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 $2.87 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 December 31, 2005 was 4.2% (2004 – 3.8%).

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 "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 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 year ended December 31, 2005, $42.1 million of 6.25% Convertible Debentures were converted, resulting in the issuance of 2,175,380 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 year ended December 31, 2005, $31.1 million of 8% Convertible Debentures were converted, resulting in the issuance of 2,187,642 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. The interest payable may also be settled with the issuance of sufficient Trust Units to satisfy the interest obligation.

At December 31, 2005, the Trust had $7.4 million in 8% Convertible Debentures outstanding with a fair market value of $11.6 million, and $57.9 million in 6.25% Convertible Debentures outstanding with a fair market value of $66.6 million.

	8% Series		**6.25% Series**		
	Number of debentures	**Amount**	**Number of debentures**	**Amount**	**Total Amount**
August 10, 2004 issuance	48,000	$ 48,000	-	$ -	$ 48,000
Converted into Trust Units	(9,581)	(9,581)	-	-	(9,581)
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

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 during the year ended December 31, 2005:

Trust Units	**Number Of Units**	**Amount**
		(restated, note 2)
Balance, December 31, 2003	44,638,376	$ 260,019
Units issued pursuant to Unit offerings	12,295,547	146,675
Units issued pursuant to corporate acquisition (Note 4)	6,931,633	78,674
Units issued pursuant to Unit Incentive Plan	153,875	1,538
Units issued pursuant to Distribution Reinvestment Plan	632,829	8,185
Units issued pursuant to conversion of debentures	674,711	9,581
Issue costs on convertible debentures converted to Trust Units	-	(383)
Trust Unit issue costs	-	(8,427)
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

c) **Redemption Right**

Unitholders may redeem their Trust Units at any time by delivering their Unit certificates to the Trustee, together with a properly completed notice requesting redemption. 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. The redemption amount will be payable on the last day of the following calendar month. The "closing market price" will be the closing price of the Trust Units on the principal market on which they are traded on the date on which they were validly tendered for redemption, or, if there was no trade of the Trust Units on that date, the average of the last bid and ask prices of the Trust Units on that date.

9. UNIT INCENTIVE PLANS

a) **Unit Incentive Plan**

PET has adopted an Unit Incentive Plan which permits the Administrator's Board of Directors to grant non-transferable rights to purchase Trust Units ("Incentive Rights") to its and affiliated entities' employees, officers, directors and other direct and indirect service providers. The purpose of the Unit Incentive Plan is to provide an effective long-term incentive to eligible participants and to reward them on the basis of PET's long-term performance and distributions. The Administrator's Board of Directors will administer the Unit Incentive Plan and determine participants, numbers of Incentive Rights and terms of vesting. The grant price of the Incentive Rights ("Grant Price") shall equal the per Trust Unit closing price on the trading date immediately preceding the date of the grant, unless otherwise permitted. The exercise price of the Incentive Rights ("Exercise Price") shall, subject to certain limitations, be reduced by deducting from the Grant Price the aggregate amounts of all distributions on a per Trust Unit basis that PET pays its Unitholders after the date of grant which represent a return of more than 2.5 percent per quarter on PET's consolidated net property, plant and equipment on its balance sheet at each calendar quarter end.

The Exercise Price will be adjusted on a quarterly basis and in no case may it be reduced to less than $0.001 per Trust Unit. The Incentive Rights are only dilutive to the calculation of earnings per Trust Unit if the exercise price is below the fair value of the Trust Units.

At December 31, 2005 a combined total of 3,963,838 (2004 – 3,963,838) Trust Units had been reserved under the Unit Incentive Plan and the Bonus Rights Plan (see note 9 (b)). As at December 31, 2005 60,875 Incentive Rights granted under the Unit Incentive Plan had vested but were unexercised (123,500 as of December 31, 2004).

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	
	2005	**2004**
Distribution yield	1.7 – 3.7 %	2.7 – 3.3%
Expected volatility	21.0%	20.0%
Risk-free interest rate	3.12 – 3.89%	3.24 - 3.99%
Expected life of Rights (years)	3.75	3.75
Vesting period of Rights (years)	4.0	4.0
Contractual life of Rights (years)	5.0	5.0
Weighted average fair value per option on the grant date	$2.91	$1.80

Rights	**Average exercise price**	**Rights**
Balance, December 31, 2003	**$ 4.22**	**1,145,500**
Granted	11.38	621,125
Exercised	3.54	(153,875)
Cancelled	-	-
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**
Rights exercisable, December 31, 2005	**$ 9.01**	**60,875**

The following summarizes information about Incentive Rights outstanding at December 31, 2005 assuming the reduced Exercise Price described above:

Range of Exercise Prices	**Number outstanding at December 31, 2005**	**Weighted average contractual life (years)**	**Weighted average exercise price/ Right**	**Number exercisable at December 31, 2005**	**Weighted average exercise price/Right**
$ 0.001	482,750	2.1	$ 0.001	-	$ -
$ 7.54 - $ 7.65	135,000	2.9	7.60	37,500	7.60
$ 8.34 - $ 13.30	351,750	3.9	9.14	23,375	10.44
$ 14.36 - $ 22.70	678,625	4.6	17.29	-	-
Total	1,648,125	4.0	$ 10.79	60,875	$ 9.01

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”). As part of a service provider’s annual bonus the Board or a committee of the Board of the Administrator may issue bonus rights to purchase Trust Units (“Bonus Rights”) in lieu of cash at a nominal price of $0.01 per Unit. The Bonus Rights vest over 2 years. Subject to approvals from Unitholders and regulatory authorities, the Trust intends to issue the required Trust Units from treasury.

Bonus Rights granted under the Plan may be exercised during a period (the "Exercise Period") no later than December 15 of the year that is three years after the end of the calendar year in which the services were provided for which Bonus Rights may be granted. 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 accrued since the grant date.

For the year ended December 31, 2005 a total of $0.6 million was recorded as compensation expense in respect of the Bonus Rights granted during the year (2004 – nil). There were no Bonus Rights vested or exercised during the year.

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

	Trust Units
Balance, December 31, 2004	-
Granted	25,478
Cancelled	(1,226)
Balance, December 31, 2005	24,252

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 $94.3 million as at December 31, 2005 based on an undiscounted total future liability of $190.2 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 7.7% to calculate the present value of the asset retirement obligation.

The following table reconciles PET's asset retirement obligations:

	2005	2004
Obligation, beginning of year	$ 34,116	$ 21,701
Obligations incurred	8,232	-
Obligations acquired (note 4)	13,267	10,325
Revision to obligation estimates	35,704	-
Expenditures for obligations during the year	(660)	-
Accretion expense	3,617	2,090
Obligation, end of year	$ 94,276	$ 34,116

11. FINANCIAL INSTRUMENTS

PET's financial instruments included in the balance sheet consist of accounts receivable, accounts payable and accrued liabilities, distributions payable and bank and other debt. The fair value of these items approximated their carrying amount at December 31, 2005 and 2004 due to their short-term nature.

Natural gas commodity price hedges

At December 31, 2005, PET had entered into financial forward sales arrangements summarized as follows:

Volumes at AECO (Gigajoules/day)("GJ/d")	Price ($/GJ)	Term
65,000 GJ/d	$ 8.40	January 2006 – March 2006
20,000 GJ/d	$ 8.01	April 2006 – October 2006

Had these contracts been settled on December 31, 2005 using prices in effect at that time, the settlement payment would have totaled $22.6 million.

12. COMMITMENTS

At December 31, 2005, the Trust had entered into physical gas sales arrangements as follows:

Volumes at AECO	Price ($/GJ)			
(Gigajoules/day)("GJ/d")	Fixed	Floor	Ceiling	Term
65,000 GJ/d	$8.50	-	-	January 2006 – March 2006
25,000 GJ/d	$8.03	-	-	April 2006 – October 2006
5,000 GJ/d	-	$9.00	$12.50	April 2006 – October 2006

13. INCOME TAXES

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

	2005	2004
Earnings (loss) before income taxes	$ 60,671	$ (44,994)
Less non-taxable earnings of the Trust	(74,135)	(25,291)
Loss for tax purposes	(13,464)	(70,285)
Combined federal and provincial tax rate	39.09%	40.43%
Computed income tax reduction	(5,262)	(28,416)
Increase (decrease) in income taxes resulting from:		
Non-deductible Crown charges	1,681	587
Resource allowance	(507)	(748)
Capital taxes	320	852
Valuation allowance	2,556	-
Change in tax rate	13	967
Future income tax reduction	$ (1,199)	$ (26,758)

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

	2005	2004
Future income taxes:		
Oil and natural gas properties	$ 6,903	$ 11,865
Asset retirement obligations	(2,765)	(1,450)
Non-capital losses	(6,390)	(8,048)
Valuation allowance	2,559	-
Other	(307)	(279)
	$ -	$ 2,088

For the entities that are not subject to tax, the net difference between the tax basis and the carrying amount is $180.2 million.

14. GAS OVER BITUMEN ISSUE

Following a Final Hearing on the matter the Alberta Energy and Utilities Board (the "AEUB") issued its final decision, Decision 2005-122 on November 12, 2005, substantially confirming the previously ordered shut-in of Wabiskaw-McMurray natural gas production in northeast Alberta. During the year ended December 31, 2005 the Trust incurred $1.0 million in legal and consulting expenditures directly related to the gas over bitumen issue (2004 - $1.2 million).

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 1 percent after the first year of shut-in increasing at 1 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 December 31, 2005 PET had recorded $41.8 million for cumulative gas over bitumen royalty adjustments received to that date.

15. SUBSEQUENT EVENT

On February 16, 2006 the Trust acquired all the issued and outstanding shares of a private oil and gas exploration and development company for cash consideration of approximately $92 million.