PARAMOUNT
ENERGY TRUST

PRESS RELEASE

PARAMOUNT ENERGY TRUST DELIVERS STRONG FINANCIAL RESULTS DESPITE 2003 REGULATORY CHALLENGES

Calgary, AB – March 3, 2004 - Paramount Energy Trust ("PET" or the "Trust) is pleased to release its strong fourth quarter and year-end 2003 results. Strong commodity prices, increased operational efficiencies, and two significant acquisitions contributed to exceptional financial results in 2003. At the same time PET exited the year with a strong balance sheet, with year-end debt to cash flow of 0.4 times. Despite major challenges posed by the Alberta Energy and Utilities Board's ("AEUB") proposed shut-in of natural gas wells in northeast Alberta, the Trust aggressively mitigated the impact on its operations.

PET will be hosting its quarterly conference call and webcast at **2:00 p.m., Calgary time, Wednesday March 3, 2004**. Interested parties are invited to take part in the conference call by calling one of the following telephone numbers 10 minutes before the start time, Toronto and area - 1 416 695 5259, outside Toronto - 1 800 446 4472. To participate in the live webcast please visit www.paramountenergy.com or www.companyboardroom.com. The webcast will also be archived shortly following the presentation.

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 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.

Paramount Energy Trust is a natural gas-focused Canadian energy trust. PET's Trust Units are listed on the Toronto Stock Exchange under the symbol "PMT.UN". 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.

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FINANCIAL AND OPERATING HIGHLIGHTS [1]	Three Months Ended December 31		Year Ended December 31	
($CDN thousands, except volume and per Trust Unit amounts)	**2003**	**2002**	**2003**	**2002**
FINANCIAL				
Revenue before royalties	41,022	40,576	201,239	123,739
Per Unit [2]	0.92	1.02	4.72	3.12
Cash flow [3]	25,138	18,756	126,360	59,699
Per Unit [2]	0.56	0.47	2.97	1.51
Net earnings (loss) [4]	(2,812)	7,497	52,434	7,406
Per Unit [2]	(0.06)	0.19	1.23	0.19
Cash distributions	26,783	n/a	123,202	n/a
Per Unit [5]	0.60	n/a	2.884	n/a
Net debt outstanding	54,189	n/a	54,189	n/a
Capital expenditures				
Exploration, Development and Other	1,043	3,893	9,084	14,296
Acquisitions	13,771	-	32,252	-
TRUST UNITS OUTSTANDING (thousands)				
End of period [7]	44,638	39,638	44,638	39,638
Weighted average [7]	44,638	39,638	42,597	39,638
Diluted	45,322	39,638	43,238	39,638
February 16, 2004	44,755	n/a	44,755	n/a
OPERATING				
Production				
Total Natural gas (Bcf)	7.5	8.4	31.2	34.6
Daily Average Natural gas (Mcf/d)	81,199	91,031	85,574	94,842
Average Prices				
Natural gas ($/Mcf)	5.49	4.89	6.44	3.57
RESERVES				
Proved plus probable [6]				
Natural gas (MMcf)	150.6	183.9	150.6	183.9
LAND (thousands of net acres)				
Undeveloped land holdings	322	364	322	364
DRILLING				
Wells Drilled (gross)				
Gas	-	-	16	16
Service	-	-	1	2
Dry	-	-	-	2
Total	-	-	17	20
Success Rate	-	-	100	90

(1) All amounts in this report include the operations and results of the northeast Alberta properties of Paramount Resources Ltd. ("PRL") which were acquired by PET during the three months ended March 31, 2003. The consolidated financial statements have been prepared on a continuity of interests basis which recognizes PET as the successor entity to PRL's northeast Alberta core area of operations as PET acquired substantially all of PRL's natural gas assets in that region.

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

(3) Management uses cash flow (before changes in non-cash working capital) to analyze operating performance and leverage. Cash flow 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. 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 Canadian GAAP. All references to cash flow throughout this report are based on cash flow before changes in non-cash working capital.

(4) Net earnings for 2002 have been restated to reflect the retroactive application of a change in accounting policy relating to Asset Retirement Obligations.

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

(6) As evaluated by McDaniel & Associates Consultants Ltd. in accordance with National Instrument NI 51-101. 2002 figures are proved plus ½ probable for comparability under NI 51-101. See "Reserves".

(7) The Trust Units indicated for periods prior to March 31, 2003 are pro forma. Actual Units were issued by PET in the first and second quarters of 2003. 9.9 million Units were issued to PRL on February 3, 2003 which in turn issued these Units to shareholders as a dividend in-kind. 29.7 million Units were issued March 10, 2003 pursuant to a Rights Offering.

FOURTH QUARTER HIGHLIGHTS

- Distributions payable for the quarter totaled $0.60 per Trust Unit representing $0.20 per Unit paid on November 17th, 2003, December 15th, 2003 and January 15th, 2004.

- Production averaged 81.2 MMcf/d representing a total decline of only 4 percent from the first quarter of 2003 despite the shut-in of 7.9 MMcf/d on September 1 pursuant to AEUB Interim Shut-in Order 03-001 on September 1, 2003.

- On November 18, 2003, PET acquired all of the outstanding shares of Epact Exploration Ltd. ("Epact") for $13.3 million plus the assumption of $4.8 million of net debt. Following the concurrent disposition of certain non-strategic Epact assets for $4.4 million, PET retained approximately 3.3 MMcf/d of gas production while establishing a new focus area in southern Alberta.

- Year-end net debt totaled $54.2 million or approximately 0.4 times 2003 cash flow.

SUBSEQUENT EVENTS

- On January 26, 2004 the AEUB Staff Submission Group ("SSG") announced its recommendations for the shut-in of gas in the northeast Alberta Athabasca Oil Sands Area. A total of 24.1 MMcf/d of PET production was recommended for shut-in which includes 7.6 MMcf/d of the gas shut-in on September 1, 2003 and an additional 16.5 MMcf/d of PET's production which was previously exempted from Interim Shut-in Order 03-001. The Trust's Legend property, representing approximately 17 MMcf/d or 20 percent of current production, was NOT recommended for shut-in although it had been under review by the SSG. An interim hearing is scheduled to begin on March 10, 2004 following which the AEUB Board will make a determination on the future producing status of wells recommended for shut-in.

- On January 27, 2004 PET announced the acquisition of producing natural gas properties in the Marten Hills area of northeast Alberta for $30.3 million, effective January 1, 2004. These assets comprise production totaling 7.4 MMcf/d and while they are within the Trust's northeast Alberta core area, they are well outside the AEUB gas/bitumen area of concern. The acquisition was financed from existing credit facilities.

- On February 18, 2004 PET announced the implementation of an industry-leading Distribution Reinvestment and Optional Trust Unit Purchase Plan ("DRIP Plan"). The DRIP Plan provides Unitholders with the opportunity to reinvest monthly cash distributions to acquire additional Trust Units at 94 percent of the market price. As well, it contains a provision for the purchase of additional Trust Units with Optional Cash Payments of up to $100,000 per Participant per financial year of PET to acquire additional Trust Units at the same six percent discount to the market price.

FULL YEAR HIGHLIGHTS

- On February 3, 2003, PET commenced operations with the acquisition of the Legend natural gas property in northeast Alberta from Paramount Resources Ltd. ("PRL") for $81 million. Attached to each of the 9.9 million Trust Units issued in connection with the Legend acquisition were three Rights to acquire three additional Trust Units for $5.05 each. The Trust Units were issued as a dividend-in-kind to shareholders of PRL. Following successful completion of the Rights Offering on March 11, 2003, which was significantly oversubscribed and raised approximately $150 million, PET acquired additional natural gas assets in northeast Alberta from PRL for $220 million.

- PET's Trust Units commenced trading on the TSX under the symbol PMT.UN on February 7, 2003. A total of 60.6 million Units traded to December 31, 2003 in the range of $8.25 to $15.45.

- Cumulative distributions payable to Unitholders for 2003 totaled $2.884 per Trust Unit representing a 57 percent return on the $5.05 investment made by Unitholders in the Trust's March Rights Offering. These distributions combined with PET's closing December 31, 2003 Unit price of $11.68 represented a total annual return of 188 percent on the Rights.

- Strong commodity prices, operational efficiencies, a successful capital expenditure program and the closing of two key acquisitions all contributed to PET achieving a 112 percent increase in cash flow to $126 million ($2.97 per Unit) in 2003 compared to $60 million ($1.51 per Unit) in 2002. These results were achieved despite the shut-in of close to 8 MMcf/d of production on September 1, 2003 resulting from the AEUB's Interim Shut-in Order for gas in the Athabasca Oil Sands Area.

- PET successfully completed a bought-deal equity financing in the second quarter raising net proceeds of $60.1 million for the issuance of 5,000,000 Trust Units at $12.65 per Unit. These proceeds were initially used to reduce bank debt and to partially fund the Trust's 2003 capital expenditure program.

- PET had some success in mitigating the effect of the AEUB's proposed policy in GB 2003-16 released on June 3, 2003 which suggested the shut-in of up to 44.4 MMcf/d of PET's production on August 1, 2003. Through consultation, technical review and government discussion, the actual policy released on July 22, 2003 in GB 2003-28 resulted in 7.9 MMcf/d shut-in on September 1, 2003. The reduced shut-in from the original policy proposed on June 3, 2003 preserved approximately $20 million of cash flow for PET in 2003. Additionally, interim royalty relief of $0.60 per Mcf of foregone production is presently providing $160,000 per month.

- Despite the AEUB shut-in on September 1, 2003, annual production declines were limited to 10 percent, averaging 85.6 MMcf/d.

OUTLOOK

PET's current production following the Marten Hills acquisition is more than 90 MMcf/d. The Trust's winter capital program in northeast Alberta is almost complete. While limited to $16 million due to the uncertainty surrounding the gas/bitumen issue, the results have been very positive and are expected to add more than 7 MMcf/d to PET's production base before spring break-up.

Recent aggressive withdrawals from natural gas storage with cold weather in heating regions and the improving North American economy have strengthened gas prices. Current 2004 average prices of approximately $6.00 per Gigajoule at AECO suggest continued strong cash flows for PET in the coming quarters.

PET submitted substantial technical evidence to the AEUB on February 23, 2004 with respect to the many wells for which the Trust objects to the shut-in recommendations of the AEUB's SSG. While the task of providing adequate technical evidence to support continued gas production prior to the AEUB deadline was impossible, some evidence was provided for all of PET's affected assets. The strain of this process on the human resources of the Trust has been extremely demanding and reprehensible. The interim hearings with respect to the matter are scheduled for March 10, 2004.

On February 27, 2004 the Alberta Court of Appeal granted a stay of the AEUB hearing process to the extent that it applies to wells for which the productive status was previously determined under AEUB Decision 2003-23 following the Chard/Leismer Hearing. This should exclude 0.7 MMcf/d of PET production from the current proceedings. PET has requested that a similar exclusion be put in effect for wells previously ruled on in AEUB Decision 2000-22 following the Surmont Hearing. This would exclude an additional 0.8 MMcf/d of PET production from the March proceedings. The Alberta Court of Appeal declined to grant a stay of the March interim hearings; however, PET and others have been granted Leave to Appeal the entire GB 2003-28 process. A date for the hearing of that appeal has not been set. PET continues to pursue all avenues to defend its gas production and Unitholder value.

PET and other affected producers continue to work with the Government of Alberta regarding the amount, timing and form of compensation with respect to any gas production that is ultimately shut-in. The Government of Alberta has expressed its objective to address this issue by the end of the first quarter of 2004 but PET cannot ensure the timing or amount of any such financial solution.

MANAGEMENT'S DISCUSSION AND ANALYSIS

The following is management's discussion and analysis ("MD&A") of Paramount Energy Trust's operating and financial results for the year ended December 31, 2003 as well as information and estimates concerning the Trust's future outlook based on currently available information. This discussion should be read in conjunction with the Trust's audited consolidated financial statements for the years ended December 31, 2003 and 2002, together with accompanying notes.

FORWARD LOOKING INFORMATION

This MD&A contains forward-looking information with respect to Paramount Energy Trust.

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 our 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 our ability to raise capital and to add to our reserves through acquisitions as well as exploration and development;
- the focus of capital expenditures on development activity rather than exploration;

- the sale, farming in, farming out or development of certain exploration properties using third party resources;
- the use of development activity and acquisitions to replace and add to reserves;
- the impact of changes in natural gas prices on cash flow after hedging;
- drilling 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 of similar size;
- our treatment under governmental regulatory regimes;
- the goal to sustain or grow production and reserves through prudent management and acquisitions;
- the emergence of accretive growth opportunities; and
- the Trust's ability to benefit from the combination of growth opportunities and the ability to grow through the capital markets.

Our 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 our operations;
- uncertainties associated with estimating reserves;
- competition for, among other things; capital, acquisitions of reserves, undeveloped lands and skilled personnel;
- 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.

EVALUATION OF DISCLOSURE CONTROLS AND PROCEDURES

The Chief Operating Officer, Susan Riddell Rose, and Chief Financial Officer, Cameron Sebastian, evaluated the effectiveness of PET's disclosure controls and procedures as of December 31, 2003 (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 operating 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.

MECHANICS OF CREATION OF THE TRUST

The Trust was formed through a series of transactions as described below:

On February 3, 2003:

(1) POT acquired the Legend property from PRL for an $81 million promissory note;
(2) PET issued approximately 9.9 million Trust Units to PRL, and
(3) PRL declared a dividend to be paid to its shareholders on February 12, 2003 of these Trust Units, at 1 Unit per 6.071646 shares, valued at $5.15 per Trust Unit, or approximately $0.85 per PRL Common Share.

On February 17, 2003:

(4) PET issued 3 Rights per Trust Unit to acquire additional Trust Units at $5.05 per Unit.

On March 11, 2003:

(5) With proceeds of the Rights Offering of approximately $150 million, which was successfully closed with full subscription on March 10, 2003, plus bank debt, PET purchased from PRL the majority of PRL's remaining Northeast Alberta natural gas assets for $220 million. The effective date of the property transactions was July 1, 2002 which, after adjustment for net cash flow and interest, resulted in the Trust assuming $70 million in bank debt.

BUSINESS PLAN AND STRATEGY

Paramount Energy Trust is a natural gas focused Canadian energy royalty trust actively managed to generate monthly cash distributions for Unitholders. The Trust's operations are focused in Canada with its core assets presently concentrated in northeast Alberta. Paramount Energy Trust is Canada's only 100 percent natural gas royalty trust.

PET seeks to be highly profitable generating premium after-tax returns at an acceptable risk for all stakeholders. Maximizing total return to Unitholders in the form of cash distributions and change in Unit price is a paramount objective. Strategies for achieving this objective include attentive management of all costs and capital expenditures, prudent use of financial leverage, optimization of our existing asset base, land stewardship and the pursuit of accretive acquisitions. At the same time, Management also attempts to mitigate commodity price volatility through an active hedging and price management program.

Paramount Energy Trust has a strategy to focus its vision of accretive growth on existing core areas and pursue field optimization and cost control within those core areas to maximize asset value. The Trust strives to control its operations whenever possible, and to maintain high working interests. PET operates over 95 percent of its properties and owns facilities which gather and process over 75 percent of its production allowing the Trust to use existing infrastructure and synergies within core areas. PET believes this high level of operatorship can translate to control over costs, timing of capital outlays and projects as well as providing competitive advantages for future opportunities.

CORPORATE GOVERNANCE

Paramount Energy Trust is committed to maintaining high standards of corporate governance. While their intent is similar, 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 U.S. 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, we already comply with proposals and recommendations that have not come into force. Full disclosure of this compliance is provided within PET's information circulars and on the Trust's website.

GAS OVER BITUMEN ISSUE

The Alberta Energy and Utilities Board ("AEUB" or the "Board") issued General Bulletin ("GB") 2003-28 (the "Bulletin") on July 22, 2003. The AEUB continues to consider that gas production in pressure communication with associated potentially recoverable bitumen places future bitumen recovery at an unacceptable risk. On January 26, 2004, the AEUB Staff Submission Group ("SSG") released their recommendations for the shut-in of producing wells with total average daily production of 135 MMcf/d as of August 31, 2003 or approximately one percent of the natural gas production of the Province of Alberta. Pursuant to Interim Shut-in Order 03-001, approximately 95 MMcf/d was shut-in by Industry on September 1, 2003. A shut-in date has not been announced for the remaining 40 MMcf/d recommended for shut-in by the SSG. A total of 24.1 MMcf/d of production net to PET was recommended for shut-in by the SSG which includes 7.6 MMcf/d of the gas shut-in on September 1, 2003 and an additional 16.5 MMcf/d of PET's production which was previously exempted from Interim Shut-in Order 03-001.

PET submitted substantial technical evidence to the AEUB on February 23 with respect to the many wells for which the Trust objects to the shut-in recommendations of the AEUB's SSG. While the task of providing adequate technical evidence to support continued gas production prior to the AEUB deadline was impossible, some evidence was provided for all of PET's affected assets. AEUB Interim Hearings with respect to this matter are scheduled to begin on March 10, 2004. On February 27, the Alberta Court of Appeal granted a stay of the AEUB hearing process to the extent that it applies to wells for which the productive status was previously determined under AEUB Decision 2003-23 following the Chard/Leismer Hearing. This should exclude 0.7 MMcf/d of PET production from the current proceedings. PET has requested that a similar exclusion be put into effect for wells previously ruled on in AEUB Decision 2000-22 following the Surmont Hearing. This would exclude an additional 0.8 MMcf/d of PET production from the March proceedings. The Alberta Court of Appeal declined to grant a stay of the March interim hearings however PET and others have been granted Leave to Appeal the entire GB 2003-28 process. A date for the hearing of that appeal has not been set.

Until the AEUB determines the final productive status of the wells, PET cannot accurately estimate the amount of production that will be shut-in, if any, and for what duration. The amount and timing of compensation for having to shut in such production is also not determinable at this time. In order to establish a base level of certainty, PET's forecasts of future cash flow and distributions assume the shut-in of gas volumes as recommended by the SSG and that any compensation for such shut-in, other than the temporary financial assistance program of $0.60 per Mcf presently in place, is delayed indefinitely. The implications of AEUB GB 2003-28 on PET's gas production have been fully described in previous press releases which can be viewed on PET's website at www.paramountenergy.com.

RESERVES

In 1998, the Alberta Securities Commission established an oil and gas taskforce to investigate methods of improving oil and natural gas reserve reports prepared pursuant to National Policy Statement 2-B ("NP 2B"), the existing legislative regime. The taskforce passed on its findings and recommendations to the Canadian Securities Administrators in 2001, which ultimately initiated its own extensive public consultation process, culminating with National Instrument 51-101 ("NI 51-101") which came into force on September 30, 2003. NI 51-101 reflects a departure from its predecessor NP 2B, attempting to address the perceived shortcomings of NP 2B by improving the standards and quality of reserve reporting and achieving a higher industry consistency.

Under NI 51-101, "Proved" reserves are those reserves that can be estimated with a high degree of certainty to be recoverable (it is likely that the actual remaining quantities recovered will exceed the estimated Proved reserves). In accordance with this definition, the level of certainty targeted by the reporting company should result in at least a 90 percent probability that the quantities actually recovered will equal or exceed the estimated reserves. There was no such consideration of probability under NP 2B. In the case of "Probable" reserves, which are obviously less certain to be recovered than Proved reserves, NI 51-101 states that it must be equally likely that the actual remaining quantities recovered will be greater or less than the sum of the estimated Proved plus Probable reserves. With respect to the consideration of certainty, in order to report reserves as Proved plus Probable the reporting company must believe that there is at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves. The implementation of NI 51-101 has resulted in a more rigorous and uniform standardization of Reserve evaluation.

Proved plus Probable reserves as defined in NI 51-101 are viewed by many industry participants as being comparable to the "Established" reserves definition that was used historically. Under the previous rules, the Established reserves category was generally calculated on the basis that Proved plus half of Probable reserves (as those terms were defined in NP 2B) represented the best estimate at the time. PET believes that its Established reserves reported under NP 2B were calculated on a conservative basis as its estimate of reserves that would ultimately be recovered. As a result, and for comparison purposes, PET has included Established reserves from its December 31, 2002 Reserve Report as the December 31, 2003 opening balances under the Proved Plus Probable reserves category reconciled on a Company Interest basis. Similarly, PET has included 50 percent of Probable reserves from the December 31, 2002 Reserve Report as the opening balances under the Probable reserves category, again reconciled on a Company Interest basis.

PET's complete NI 51-101 reserves disclosure as at December 31, 2003 including underlying assumptions regarding commodity prices, expenses and other factors and reconciliation of reserves on a Net Interest Basis (working interest less royalties payable), will shortly be available in the Trust's Annual Information Form and on the Trust's website at www.paramountenergy.com.

The following table sets forth PET's reserves on a Gross (working interest) and a Net (working interest less royalties payable) as evaluated by McDaniel & Associates Consultants Ltd. independent reserve consultants ("McDaniel") as of December 31, 2003. Substantially all of PET's reserves are natural gas and McDaniel evaluates 100 percent of the Trust's reserves. The reserves presented are divided into two sub-categories, "Without Gas/Bitumen", being those reserves not recommended for shut-in by the AEUB Staff Submission Group and "With Gas/Bitumen", being those reserves recommended for shut-in by the AEUB Staff Submission Group.

NATURAL GAS RESERVES

	Gross Reserves [c]			Net Reserves [d]		
Reserve Category	Without Gas/ Bitumen[a]	With Gas/ Bitumen[b]	Total	Without Gas/ Bitumen[a]	With Gas/ Bitumen[b]	Total
Proved Producing[f]	102.6	14.2	116.8	82.0	11.9	93.9
Proved Non-Producing[g]	2.8	4.6	7.4	2.3	3.9	6.2
Proved Undeveloped[h]	0.7	-	0.7	0.5	-	0.5
Total Proved[e]	106.1	18.8	124.9	84.8	15.8	100.6
Probable	16.5	9.2	25.7	13.2	7.8	21.0
Total Proved & Probable[i]	122.6	28.0	150.6	98.0	23.6	121.6

Columns may not add due to rounding.

(a) "Without Gas/Bitumen" represents those reserves not recommended for shut-in by the AEUB Staff Submission Group.

(b) "With Gas/Bitumen" represents those reserves recommended for shut-in by the AEUB Staff Submission Group. Reserves related to production which is currently shut-in as a result of AEUB Interim Shut-in Order 03-001 have been categorized as probable reserves.

(c) "Gross Reserves" are the total of the Trust's working interest share of reserves before deducting royalties owned by others.

[d] "Net Reserves" are the total of the Trust's working interest share of reserves after deducting the amount attributable to the royalties owned by others.

[e] "Proved Reserves" means those reserves estimated as recoverable under current technology and existing economic conditions from that portion of a reservoir which can be reasonably evaluated as economically productive on the basis of analysis of drilling, geological, geophysical and engineering data, including the reserves to be obtained by enhanced recovery processes demonstrated to be economic and technically successful in the subject reservoir. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to PET's reserves in the area.

[f] "Proved Producing Reserves" means those proved reserves that are actually on production, or if not producing, that could be recovered from existing wells or facilities and where the reasons for the current non-producing status is the choice of the owner. An illustration of such a situation is where a well or zone is capable but is shut-in because its deliverability is not required to meet contract commitments. Reserves assigned to non-producing zones in producing wells were classified as producing if the reserve quantities were estimated to be minor relative to PET's reserves in the area.

[g] "Proved Non-Producing Reserves" means those non-producing proved reserves recoverable from existing wells that require relatively minor capital expenditure to produce.

[h] "Proved Undeveloped Reserves" means those reserves expected to be recovered from new wells on undrilled acreage or from existing wells where a relatively major capital expenditure will be required.

[i] "Proved & Probable Reserves" reflect at least a 50% probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

The following table sets forth a reconciliation of the Company Interest reserves, with and without gas over bitumen of PET for the years ended December 31, 2003 and 2002 derived from the McDaniel reports at those dates using consultant's average pricing. PET's Company Interest reserves include working interest and/or royalties receivable.

COMPANY INTEREST RESERVES – CONSULTANT'S AVERAGE PRICING

	Natural Gas (BCF)			Barrel of Oil Equivalent (MMBOE) [d]		
	Proved	Probable [a]	Proved Plus Probable [a][b]	Proved	Probable [a]	Proved Plus Probable [a][b]
December 31, 2002	164.3	19.7	183.9	27.4	3.3	30.7
Capital Additions[c]	2.7	0.6	3.3	0.5	0.1	0.5
Technical Revisions	(21.6)	3.9	(17.7)	(3.6)	0.6	(3.0)
Acquisitions	10.7	1.5	12.2	1.8	0.2	2.0
Dispositions	-	-	-	-	-	-
Production	(31.2)	-	(31.2)	(5.2)	-	(5.2)
December 31, 2003	124.9	25.7	150.6	20.8	4.3	25.0

Columns may not add due to rounding.

[a] Probable reserves at December 31, 2002 represent 50 percent of Probable reserves reported in PET's December 31, 2002 reserve report. Proved plus Probable figures for December 31, 2002 represent Established Reserves from PET's December 31, 2002 Reserve Report. Proved plus Probable illustrates the transition between Established reserves at December 31, 2002 under NP 2B to Proved plus Probable reserves as at December 31, 2003 under NI 51-101. However, Proved plus Probable Reserves at December 31, 2003 may not be strictly comparable to Established Reserves at December 31, 2002. See initial discussion above under "Reserves".

[b] Proved plus Probable reserves reflect at least a 50 percent probability that the quantities actually recovered will equal or exceed the sum of the estimated Proved plus Probable reserves.

[c] Includes Discoveries, Extensions, and Improved Recoveries.

[d] Natural gas has been converted to oil equivalent volumes on the basis of 6 Mcf equals one barrel of oil.

The 2003 revisions to proved reserves relate principally to changes in the consultant's estimate of gas shrinkage volumes in certain of the Trust's properties as well a downward revision in the Trust's reserves in the Legend area. The revision at Legend is categorized as a technical revision related to production performance. It is worthy of note that this downward revision at Legend essentially reverses a positive revision on the same property made by the consultant at December 31, 2002 related to better than anticipated production performance. While reserve estimates have been revised downward in compliance with NI 51-101, actual production from all properties continues to meet the Trust's expectations.

ENVIRONMENTAL REMEDIATION AND ABANDONMENT

In connection with its NI 51-101 disclosure obligations, PET engaged Prevent Technologies Ltd. to prepare a summary (the “Net Liability Report”) of abandonment and reclamation costs for PET’s surface leases, wells and facilities as well as estimated related salvage value. The net liability report identifies total expected future costs of $46.4 million for the decommissioning, abandonment and reclamation of PET’s assets. Related salvage value is estimated at $59.1 million for plants, equipment and facilities for a net expected future gain to the Trust of $12.7 million.

PRODUCTION VOLUMES

Production volumes averaged 85.6 MMcf/d in 2003 compared to 94.8 MMcf/d in 2002, a decrease of 10 percent. Natural production declines as well as the 7.9 MMcf/d of natural gas sales shut-in pursuant to AEUB Interim Shut-in Order 03-001 on September 1, 2003 were offset by a successful capital program as well as the acquisition of the Ells property in March, Epact Exploration in November and other minor acquisitions which consolidated some of the Trust’s interests in its properties. The Trust estimates that the year-over-year production volume decrease would have been less than 7 percent without the shut-in of gas on September 1, 2003 pursuant to the AEUB Shut-in Order.

Production	**2003**	2002	% Change
Natural Gas (MMcf/d)	**85.6**	94.8	(10)

COMMODITY PRICES

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 Hub prices were $6.70 per Mcf and $4.07 per Mcf for 2003 and 2002 respectively, 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 58 percent from $3.88 per Mcf in 2002 to $6.13 per Mcf in 2003.

PET’s average well head gas price, prior to hedging transactions, increased by 71 percent to $6.11 per Mcf in 2003 from $3.57 per Mcf in 2002. PET’s average gas price after hedging transactions was $6.44 per Mcf and $3.57 per Mcf in 2003 and 2002 respectively.

Prices and Marketing	**2003**	2002	% Change
Reference prices			
AECO gas ($/Mcf)	**$ 6.70**	$ 4.07	65
Alberta Gas Reference Price ($/Mcf)	**$6.13**	$3.88	58
Average PET prices			
Natural gas, before hedging ($/Mcf)	**$ 6.11**	$ 3.57	71
% AECO, before hedging	**91%**	88%	
% Alberta Gas Reference Price, before hedging	**100%**	92%	
Natural gas, after hedging ($/Mcf)	**$ 6.44**	$ 3.57	80
% AECO, after hedging	**96%**	88%	
% Alberta Gas Reference Price, after hedging	**105%**	92%	

REVENUE

Natural gas revenue in 2003 was $201.2 million, representing a 63 percent increase from $123.7 million in 2002. Revenue growth was achieved via higher natural gas prices coupled with prudent hedging.

Revenue

($ thousands)	**2003**	2002	% Change
Natural gas revenue, before hedging	**190,921**	123,739	55
Hedging receipts	**10,318**	-	-
Total revenue	**201,239**	123,739	63

HEDGING AND RISK MANAGEMENT

The Trust's hedging 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. In addition hedging may be used to ensure the economics related to significant acquisitions. Generally the Trust limits its hedging activity for any given period to 50 percent of forecast production for that period.

In 2003, the Trust's hedging activities resulted in a net receipt of $10.3 million or $0.33 per Mcf. 2002 activity did not include any hedging as the 2002 results represent an allocation of the northeast Alberta operations of Paramount Resources Ltd ("PRL").

PET currently has the following natural gas hedges in place:

Volumes at AECO (Gigajoules/day)("GJ/d")	**Price ($/GJ)**	**Term**
45,000 GJ/d	$ 6.30	January 2004 – March 2004
35,000 GJ/d	$ 5.56	April 2004 – October 2004
7,500 GJ/d	$ 5.00 to 7.10	April 2004 – December 2004
15,000 GJ/d	$ 6.42	November 2004 – March 2005

ROYALTIES

Alberta Gas Crown Royalties are a cash royalty calculated on the Crown's share of production using the Alberta Gas Reference Price. Credits are applied to account for the Crown's share of allowable capital costs, operating costs and processing fees.

Royalty expense increased 75 percent to $38.2 million in 2003 from $21.9 million in the previous year. This percentage increase exceeded the 63 percent increase in revenue as royalties in Alberta are calculated on a sliding scale which increases the overall royalty rate as natural gas prices increase like they did in 2003.

Royalties

($ thousands except where noted)	**2003**	2002	% Change
Natural gas royalties	**38,209**	21,886	75
Per Unit ($/Mcf)	**1.22**	0.63	94
Percentage of sales (%)	**19.0**	17.7	

OPERATING COSTS

Operating costs decreased by 8 percent to $27.7 million ($0.89 per Mcf) in 2003 from $30.3 million ($0.87 per Mcf) in 2002. On a unit of production basis operating costs were relatively unchanged. In northeast Alberta approximately 80 percent of production costs are fixed and 20 percent are variable with production volumes. The decrease in total costs resulted from the decline in average production levels in 2003, low operating costs for the Ells property acquired in March 2003 as well as the increased focus by PET on cost control in its field operations. Unit costs were held constant despite an overall industry trend towards increasing operating costs resulting from competitive conditions and a shortage of oilfield services.

Operating Costs

($ thousands except where noted)	**2003**	2002	% Change
Operating costs	**27,727**	30,265	(8)
Per Unit ($/Mcf)	**0.89**	0.87	2

OPERATING NETBACKS

PET's 2003 operating netback of $4.33 per Mcf represented a 109 percent increase from $2.07 in 2002 and reflected an 80 percent increase in realized natural gas prices partly offset by a 94 percent increase in royalties per Mcf and a 2 percent increase in operating costs on a unit of production basis.

Netback

($ per Mcf)	**2003**	2002	% Change
Gas price	**6.44**	3.57	80
Royalties	**(1.22)**	(0.63)	94
Operating costs	**(0.89)**	(0.87)	2
Netback	**4.33**	2.07	109

GENERAL AND ADMINISTRATIVE EXPENSE

General and administrative expenses, net of overhead recoveries on operated properties, increased to $4.7 million ($0.19 per Mcf) in 2003 from $4.0 million ($0.12 per Mcf) in 2002. While routine expenditures were held constant, the 2003 total included $0.7 million in legal and consulting expenditures directly related to the AEUB gas/bitumen issue.

General and Administrative Expense	**2003**		2002	
	$000's	**$ / Mcf**	$000's	$ /Mcf
General & administrative	**3,980**	**0.15**	3,987	0.12
Gas/bitumen costs	**696**	**0.04**	-	-
Total general & administrative	**4,676**	**0.19**	3,987	0.12

INTEREST EXPENSE

PET commenced bank borrowing in March 2003 with the acquisition of assets from PRL. Interest on bank borrowings was generally paid at Bankers Acceptance rates plus a stamping fee of 150 basis points.

Interest Expense

($ thousands except where noted)	**2003**	2002	% Change
Interest expense	**2,440**	50	---
Per Unit ($/Mcf)	**0.08**	---	

DEPLETION, DEPRECIATION AND ACCRETION

The 2003 depletion, depreciation and accretion (DD&A) rate increased to $2.01 per Mcf from $1.49 per Mcf in 2002, primarily due to the decrease in the Trust's proved reserves at December 31, 2003 as well as the Epact acquisition. The DD&A rate includes depletion of $2.3 million ($2.3 million in 2002) on the capitalized cost associated with the asset retirement obligation as well as accretion expense on the asset retirement obligation of $1.2 million in 2003 ($1.2 million in 2002). The retroactive application of the new accounting policy for asset retirement obligations required restatement of prior periods.

Depletion, Depreciation and Accretion

($ thousands except where noted)	**2003**	2002	% Change
Depletion expense	**61,436**	50,383	22
Accretion of asset retirement obligation	**1,239**	1,163	7
Total	**62,675**	51,546	22
Per Unit ($/Mcf)	**2.01**	1.49	35

INCOME TAXES

For income tax purposes PET is able to and intends to claim deduction for all amounts paid or payable to the Unitholder, then allocate remaining taxable income, if any, to the Unitholders. Accordingly, no current or future income taxes have been recorded in 2003. In 2002 an amount of current tax expense was recorded which represented an allocation of the current taxes of PRL to its northeast Alberta operations.

CAPITAL EXPENDITURES

Exclusive of the series of transactions including the acquisitions of properties from PRL which created the Trust, PET expended $8.3 million on exploration and development activities in its core areas. In addition the Ells property was acquired for $18.4 million in March and Epact Exploration Ltd. was acquired in November for $13.3 million.

Capital Expenditures

($ thousands except where noted)	**2003**	2002	% Change
Exploration & development expenditures	**8,327**	11,468	(21)
Acquisitions	**32,252**	-	-
Properties acquired from PRL	**269,162**	-	-
Other	**757**	2,828	(73)
Total	**310,498**	14,296	-

The Board of Directors of the Administrator of PET has approved a capital budget for exploration and development expenditures of $20 million for 2004.

COST RECOVERY TEST

PET performs cost recovery 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.

Although the sum of the expected future cash flows for the total of all of PET's assets greatly exceeds the carrying amount, cost recovery tests carried out at a property level did identify some impairment at December 31, 2003. Application of this test at December 31, 2003 resulted in a reduction of the carrying value of PET's property, plant and equipment of $9.8 million. This amount arose in connection with the increase in capital assets related to the Asset Retirement Obligation, revisions to PET's reserves and adjustments to estimates of future cash flows related to the gas/bitumen issue. No future compensation with respect to the gas/bitumen issue for any gas/bitumen shut-in production beyond the current interim financial assistance of $0.60 per Mcf on current or future foregone production was included in this determination. To the extent that circumstances including volumes of gas shut-in or finalization of compensation arrangements change, further adjustments to the carrying amount of PET's property, plant and equipment may be required. Such adjustments relate to prescribed determinations under the successful efforts method of accounting and should not be taken to represent indications of the fair market value of PET's assets or the possible impairment of such value.

CAPITALIZATION AND FINANCIAL RESOURCES

PET commenced bank borrowing in March 2003. At December 31, 2003, PET had bank debt outstanding of $55.6 million and a working capital surplus of $1.4 million. Subsequent to December 31, 2003 the Trust's available credit facilities were increased from $75 million to $100 million.
PET has a revolving credit facility with a syndicate of Canadian Chartered Banks. The facility consists of a demand loan of $90 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 $1.7 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.

December 31, 2003 net debt to total capitalization was 9.4 percent and net debt to 2003 cash flow was 0.4 years.

Capitalization and Financial Resources

$ thousands except per Trust Unit and percent amounts	**2003**
Bank and other debt	**55,564**
Working capital	**(1,375)**
Net debt	**54,189**
Trust Units outstanding (000's)	**44,638**
Market price at end of period	**11.68**
Market value of Trust Units	**521,372**
Total capitalization [(1)]	**575,561**
Net debt as a percent of total capitalization	**9.4%**
Cash flow	**126,360**
Net debt to cash flow ratio	**0.4**

(1) 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.

In February, 2004 PET closed the acquisition of producing natural gas properties in the Marten Hills area of northeast Alberta for $30.3 million. The acquisition was financed from existing credit facilities.

UNITHOLDERS' EQUITY

PET's total capitalization was $575.6 million at December 31, 2003 with the market value of the Trust Units representing 91 percent of total capitalization. During 2003, the market price of the Trust Units ranged from $8.25 to $15.45 with an average daily trading volume of 236,000 Units.

On December 31, 2003 there were 44.6 million Trust Units outstanding. All Trust Units were issued during 2003 as follows:

- 9.9 million Trust Units were issued on February 3, 2003 to PRL. All these Units were distributed by way of a dividend in-kind to the shareholders of PRL.
- On March 11, 2003 PET issued 29.7 million Trust Units to Unitholders pursuant to a Rights Offering.
- On May 30, 2003 PET closed an equity financing issuing 5 million Trust Units at $12.65 per Unit for net proceeds of $60.1 million.

CASH DISTRIBUTIONS

PET declared cash distributions of $123.2 million ($2.884 per Unit) in 2003 representing 97 percent of 2003 cash flow.

Taxation of 2003 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 2003 taxation year, the split between the two is 52 percent taxable and 48 percent tax deferred.

PET, in consultation with its tax advisors, is of the view that the 2003 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 2003, 47.8 percent would be reported as qualified dividends and 52.2 percent would be reported as non-taxable return of capital for U.S. Persons. PET performed an Earnings and Profits calculation for U.S. tax purposes in order to make this determination.

2003 Distributions by Month
($ per Trust Unit)

Payment Date	Taxable Amount	Tax Deferred Amount (Return of Capital)	Total Distribution
April 15, 2003	$ 0.432	$ 0.398	$ .830
May 15, 2003	0.144	0.133	.277
June 16, 2003	0.144	0.133	.277
July 15, 2003	0.130	0.120	.250
August 15, 2003	0.130	0.120	.250
September 15, 2003	0.104	0.096	.200
October 15, 2003	0.104	0.096	.200
November 17, 2003	0.104	0.096	.200
December 15, 2003	0.104	0.096	.200
January 15, 2004	0.104	0.096	.200
Total	**$ 1.500**	**$ 1.384**	**$ 2.884** (1)
Percent	**52.0%**	**48.0%**	**100.0%**

(1) Total is based upon cash distributions paid and payable during 2003

2004 Cash Distributions

After a payout of $0.20 per Trust Unit for January 2004, monthly cash distributions were set at $0.16 per Trust Unit for February 2004. It is expected that this newly-established level of monthly distribution will be sustainable for the foreseeable future assuming the current forward market for natural gas prices, the shut-in of additional volumes of gas due to the gas/bitumen issue as recommended by the AEUB SSG and that compensation for such shut-in, other than the temporary financial assistance program presently in place, is delayed beyond the date of shut-in. Distributions are subject to review monthly based on PET's production and commodity price fluctuations. Revisions, if any, to the forecast monthly distributions will be determined as required in the context of prevailing and anticipated conditions at that time.

CASH FLOW SENSITIVITY FOR THE YEAR 2004

Below is a table that shows sensitivities of PET's 2004 cash flow to operational changes and changes in the business environment:

		Impact on Annual Cash Flow	
	Change	**$/Trust Unit**	**%**
Business Environment			
Price per Mcf of natural gas (CDN$AECO)	$ 0.50/GJ	0.216	10
CAD/USD exchange rate	$ 0.01	0.037	2
Interest rate on debt	1%	0.021	1
Operational			
Gas production volume	1 MMcf/d	0.026	1
Operating costs per Mcf	$ 0.10/Mcf	0.060	3
Cash G&A expenses per Mcf	$ 0.05	0.030	1

These sensitivities assume operating costs of $0.95 per Mcf, general and administrative expenses of $0.15 per Mcf, a Canadian/U.S exchange rate of $0.75 and an interest rate on debt of 4.5 percent.

Given the uncertainty surrounding the gas/bitumen issue and the range of possible production volumes which may or may not be shut-in in the future, the following table presents estimated 2004 monthly average cash flow per unit at various assumed average annual gas prices and production levels and assuming no compensation for any gas/bitumen shut-in production beyond the current interim financial assistance of $0.60 per Mcf on current or future foregone production. Incorporating the current forward market for natural gas, average calendar 2004 AECO gas prices are currently estimated at approximately $6.00/GJ.

	Average 2004 AECO Gas Price ($/GJ)				
	$ 5.00	**$ 5.50**	**$ 6.00**	**$ 6.50**	**$ 7.00**
Production (MMcf/d)	Average 2004 Cash Flow ($/Unit/Month)				
85	0.171	0.186	0.204	0.222	0.241
80	0.162	0.176	0.193	0.209	0.226
75	0.154	0.166	0.181	0.197	0.212
70	0.146	0.157	0.170	0.184	0.198

FINANCIAL REPORTING AND REGULATORY UPDATE

There have been several changes in the financial reporting and securities regulatory environment in 2003 that have impacted the Trust and all public entities. Canadian securities regulators and the Canadian Institute of Chartered Accountants ("CICA") are undertaking these measures to increase investor confidence through increased transparency, consistency and comparability of financial statements and financial information. As well, the changes have been brought about by a goal of aligning Canadian standards more closely with those in the United States.

The following new and amended standards were implemented by the Trust in 2003 and their impact as reflected in the 2003 financial statements:

Asset Retirement Obligations – The CICA issued Section 3110 which harmonizes Canadian GAAP with SFAS No.143 "Accounting for Asset Retirement Obligations". The new Canadian standard is effective for fiscal years beginning on or after January 1, 2004. However, earlier adoption is encouraged. PET implemented this standard in 2003 in accordance with the early adoption provisions of the standard. As a result of implementation, the liability for future abandonment costs (the "Asset Retirement

Obligation" or "ARO") increased to $21.7 million and the carrying amount of property, plant and equipment increased by $7.4 million. Net earnings for 2003 of $53.3 million decreased by $0.9 million compared to net earnings which would have been reported under the old standard. The transitional provisions of this section require that the standard be applied retroactively with restatement of comparative periods. As a result of the retroactive application, 2002 comparative numbers have been restated to reflect that impact of the standard on the 2002 financial statements. Net earnings for 2002 of $9.0 million decreased by $1.6 million, the ARO increased to $20.0 million, the carrying amount of property, plant and equipment increased by $9.3 million and opening 2002 retained earnings decreased by $2.0 million. Opening 2003 accumulated earnings decreased by $3.6 million for the cumulative impact of retroactive restatement of all prior years.

Disclosure of Guarantees – In February 2003, the CICA issued Accounting Guideline 14 "Disclosure of Guarantees" which requires that all guarantees be disclosed in the notes to the financial statements along with a description of the nature and term of the guarantee and an estimate of the fair value of the guarantee. The new guideline is effective for fiscal years beginning on or after January 1, 2003. Implementation of the new guideline did not impact PET's financial results for 2003.

The following new and amended standards are expected to impact the Trust in 2004 as follows:

Stock Based Compensation and Other Stock Based Payments – In September 2003, the CICA issued an amendment to section 3870 "Stock based compensation and other stock based payments". The amended section is effective for fiscal years beginning on or after January 1, 2004.

Hedging Relationships – In December 2001, the CICA issued Accounting Guideline 13 "Hedging Relationships" that deals with the identification, designation, documentation and measurement of effectiveness of hedging relationships for the purposes of applying hedge accounting. Accounting Guideline 13 is intended to harmonize Canadian GAAP with SFAS No.133 "Accounting for Derivatives Instruments and Hedging Activities". The guideline is effective for fiscal years beginning on or after July 1, 2003.

Continuous Disclosure Obligations – Effective March 31, 2004, the Trust and all reporting issuers in Canada will be subject to new disclosure requirements as per National Instrument 51-102 "Continuous Disclosure Obligations". This new instrument is effective for fiscal years beginning on or after January 1, 2004. The instrument proposes shorter reporting periods for filing of annual and interim financial statements, MD&A and the Annual Information Form ("AIF"). The instrument also proposes enhanced disclosure in the annual and interim financial statements, MD&A and AIF. Under this new instrument, it will no longer be mandatory for the Trust to mail annual and interim financial statements and MD&A to Unitholders, but rather these documents will be provided on an "as requested" basis. It is PET's intention to make these documents available on the Trust's website on a continuous basis.

Impact on Net Earnings of Change in Accounting Policies

The implementation of a new accounting policy relating to asset retirement obligations has resulted in restatement of previously reported annual and quarterly net earnings. The restatement was required per the transitional provisions of the accounting standard.

The following table illustrates the impact of the new accounting policy on annual net income for the years and quarters which have been presented for comparative purposes:

($ thousands)	Q4	Q3	2003 Q2	Q1	Total
Net Earnings (loss) before changes in accounting policies [1]	**(2,574)**	**11,993**	**17,502**	**26,416**	**53,337**
Increase (decrease) in net earnings: Asset retirement obligation [2]	**(238)**	**323**	**(518)**	**(470)**	**(903)**
Net Earnings (loss) after change in accounting policies	**(2,812)**	**12,316**	**16,984**	**25,946**	**52,434**

($ thousands)	Q4	Q3	2002 Q2	Q1	Total
Net Earnings (loss) before changes in accounting policies [1]	7,117	1,737	4,614	(4,427)	9,041
Increase (decrease) in net earnings: Asset retirement obligation [2]	380	(723)	(671)	(621)	(1,635)
Net Earnings (loss) after change in accounting policies	7,497	1,014	3,943	(5,048)	7,406

(1) This represents net earnings as reported before retroactive restatement for changes in accounting policies.

(2) The new accounting policy for asset retirement obligations was implemented in the fourth quarter of 2003. This new standard requires retroactive application with restatement of all periods presented for comparative purposes.

QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

PET's operations are effected 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.

Cyclical and Seasonal Impact of 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.

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

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 products. 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 counterparty. In 2003, approximately 38 percent of natural gas production was sold to aggregators, 18 percent was sold at fixed prices, 39 percent was sold into the Alberta spot market and 5 percent to the long-term export market with price indexed to the AECO monthly index.

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.

Paramount Energy Trust
Consolidated Balance Sheets

As at	December 31, 2003	December 31, 2002
($ thousands)		
Assets		
Current Assets		
Accounts Receivable	$ 19,029	$ 16,012
Property, Plant and Equipment (Notes 4 and 5)	241,955	261,336
	$ 260,984	$ 277,348
Liabilities		
Current Liabilities		
Accounts Payable and Accrued Liabilities	$ 8,726	$ 19,306
Distributions Payable	8,928	-
Bank and Other Debt (Note 6)	55,564	2,123
	73,218	21,429
Asset Retirement Obligations (Notes 3, 5 and 9)	21,701	20,039
Unitholders' Equity		
Unitholders' Capital (Note 7)	260,018	-
Equity Adjustments (Notes 1 and 5)	(16,172)	1,317
Net Investment of Paramount Resources Ltd.	-	234,563
Accumulated Earnings Net of Distributions	(77,781)	-
	166,065	235,880
	$ 260,984	$ 277,348

See Accompanying Notes
Basis of Presentation: Notes 1 and 2
Gas/Bitumen Issue: Note 11
Subsequent Event: Note 5

Paramount Energy Trust
Consolidated Statements of Earnings and Accumulated Earnings

	Year Ended December 31 2003	2002
($ thousands except per unit amounts)		
Revenue		
Natural Gas	$ 201,239	$ 123,739
Royalties	(38,209)	(21,886)
	163,030	101,853
Expenses		
Production	27,727	30,265
Dry Hole	1,323	246
Geological and Geophysical	128	367
Lease Rentals	1,827	1,825
General and Administrative	3,980	3,987
Gas Over Bitumen Costs (Note 11)	696	-
Interest	2,440	50
Income Taxes (Note 2(g))	-	6,027
Loss on Sale of Equipment	-	134
Write-down of Property, Plant and Equipment (Note 5)	9,800	-
Depletion, Depreciation and Accretion	62,675	51,546
	110,596	94,447
Net Earnings	52,434	7,406
Accumulated Earnings Net of Distributions at Beginning of Year, as previously reported	238,203	282,815
Retroactive Effect of Change in Accounting Policy (Note 3)	(3,640)	(2,005)
Accumulated Earnings Net of Distributions at Beginning of Year, as restated	234,563	280,810
Reduction in Net Investment on Restructuring (Notes 1 and 2)	(241,576)	-
Distributions Paid or Payable	(123,202)	(53,653)
Accumulated Earnings Net of Distributions at End of Year	$ (77,781)	$ 234,563
Earnings Per Trust Unit (Note 2(d))		
Basic	$ 1.23	$ 0.19
Diluted	$ 1.21	$ 0.19
Distributions Per Trust Unit	$ 2.884	-

See Accompanying Notes

Paramount Energy Trust
Consolidated Statements of Cash Flows

	Year Ended December 31 2003	2002
($ thousands)		
Cash Provided By (Used For)		
Operating Activities		
Net Earnings	$ 52,434	$ 7,406
Items not Involving Cash		
Depletion, Depreciation and Accretion	62,675	51,546
Loss on Sale of Equipment	-	134
Write-down of Property, Plant and Equipment	9,800	-
Items not Associated with Operations		
Dry Hole	1,323	246
Geological and Geophysical	128	367
Funds Flow from Operations	126,360	59,699
Change in Non-Cash Working Capital	(13,941)	5,860
	112,419	65,559
Financing Activities		
Issue of Trust Units	260,018	-
Distributions to Unitholders	(123,202)	(53,653)
Change in Bank and Other Debt	53,441	2,123
Change in Non-Cash Working Capital	8,928	-
	199,185	(51,530)
Funds Available for Investment	311,604	14,029
Investing Activities		
Dry Hole	(1,323)	(246)
Geological and Geophysical	(128)	(367)
Acquisition of Properties, net	(301,414)	-
Corporate Assets	-	(2,828)
Change in Non-Cash Working Capital	345	880
Exploration and Development Expenditures	(9,084)	(11,468)
	$ (311,604)	$ (14,029)

See Accompanying Notes

1. PARAMOUNT ENERGY TRUST CREATION AND FINANCING

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 dated June 28, 2002, as amended, and whose trustee is Computershare Trust Company of Canada. The beneficiaries of PET are the holders of the Trust Units of PET (the "Unitholders"). PET was established for the purposes of issuing Trust Units and acquiring and holding royalties and other investments. The consolidated financial statements of PET consist of 100 percent ownership of Paramount Energy Operating Corp. (the "Administrator") and the 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 will provide certain management and administrative services for PET and its trustee pursuant to a delegation of power and authority to it under the PET indenture.

On July 1, 2002, PET entered into an agreement with a subsidiary of PET's then-parent Paramount Resources Ltd. ("PRL") to acquire corporate assets. As the transaction was between related parties, the assets acquired were recognized at a value equal to their net book value in the books of the vendor. This resulted in an increase in the carrying value of the assets of $1.3 million and an equivalent increase in Unitholders' Equity (Note 5).

The issuance of a receipt for a prospectus was made by Canadian regulatory authorities on January 29, 2003 and by regulators in the United States on February 3, 2003. Subsequent to the issuance of these receipts, PET, POT, the Administrator and PRL completed a series of transactions pursuant to which PET, on a consolidated basis, acquired oil and gas properties and related assets with an estimated value of $301,000,000 from PRL. PET raised equity of approximately $150,000,000 from the exercise of rights and obtained bank financing of approximately $100,000,000. The series of transactions were as follows:

On February 3, 2003, PRL, effective July 1, 2002, sold its interest in certain assets (the "Initial Assets") to POT for consideration consisting of a promissory note in PRL's favor of $81,000,000. Interest on the $81,000,000 purchase price accrued at a rate of 6.5 percent per annum. At that time a secured guarantee was given by both POT and PET in respect of $20,000,000 of PRL's indebtedness to PRL's lenders. At the same time PRL and POT executed the Take-Up Agreement which required PRL to sell and POT to purchase 100 percent of PRL's interest in certain additional assets (the "Additional Assets"). The purchase price was $220,000,000. POT paid a $5,000,000 deposit on the purchase price of these assets through the issuance of a non-interest bearing promissory note. As related party transactions, the purchase price of the acquired Initial and Additional Assets was adjusted to reflect the seller's net book value of the assets. This resulted in a reduction in the carrying value of petroleum and natural gas properties of $17.5 million. This amount was recorded as a reduction in Unitholders' Equity (Note 5);

- POT, effective July 1, 2002, granted to PET a royalty of 99 percent of the net revenue less permitted deductions with respect to debt payments, capital expenditures and certain other amounts from the Canadian resource properties comprised in the Initial Assets and all after-acquired Canadian resource properties of POT including the Additional Assets described below (the "Royalty") in exchange for consideration consisting of $64,152,000 to be paid in accordance with an agreement between POT, PET and PRL whereby PET issued and delivered to PRL a first promissory note in the amount of $30,000,000 and a second promissory note in the amount of $34,152,000. The first promissory note carried annual interest equal to the prime rate of a major Canadian chartered bank from time to time plus 1.875 percent. This payment reduced the amount of indebtedness that POT owed to PRL to approximately $16,848,000 which was represented by a promissory note that carried annual interest from the date of issue equal to the prime rate of a major Canadian chartered bank from time to time plus 1.875 percent. PET granted a security interest to PRL in PET's assets as security for its indebtedness under the first promissory note and POT granted a guarantee to PRL for such indebtedness and granted PRL a security interest over its assets for the guarantee;

- PET issued 6,636,045 Trust Units to PRL in full repayment of the indebtedness under the second promissory note;

- PET purchased from PRL the remaining $16,848,000 indebtedness owed by POT to PRL in exchange for the issuance and delivery to PRL of an additional 3,273,721 Trust Units;

- PRL did, on February 4, 2003, by way of a dividend, distribute all of the PET Trust Units held by PRL, being all 9,909,767 Trust Units, to the holders of PRL common shares;

- PET issued to each of the holders of the Trust Units distributed by PRL, three rights to subscribe for additional PET Trust Units. Each right entitled the holder to purchase one additional PET Trust Unit at a subscription price of $5.05 per Trust Unit. On March 11, 2003, PRL did, effective July 1, 2002, sell to POT 100 percent of PRL's interest in the Additional Assets for an aggregate consideration of $220,000,000. This was funded by the exercise and payment of 100 percent of the rights granted, resulting in proceeds of $150,129,475 (before issue costs). These funds together with bank financing of $100,000,000 were also used to repay the $30,000,000 promissory note to PRL and to complete the acquisition of the Additional Assets.

- Effective March 19, 2003 POT acquired a 100 percent interest in the Ells property in northeast Alberta from PRL for $19.9 million.

- On May 30, 2003 PET closed an issue of 5,000,000 Trust Units at $12.65 per Unit for net proceeds of $60.3 million.

2. BASIS OF PRESENTATION AND ACCOUNTING POLICIES

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").

Prior to the asset acquisitions on February 3, 2003 and March 11, 2003 described in Note 1, the consolidated financial statements include the operations and results of the northeast Alberta properties of PRL which were acquired by the Trust on those dates. The consolidated financial statements have been prepared on a continuity of interests basis which recognizes the Trust as the successor entity to PRL’s northeast Alberta core area of operations given that the Trust acquired substantially all of PRL’s natural gas assets in that region. Certain of PRL’s properties in northeast Alberta were not acquired by the Trust and the results of such properties have been excluded from these consolidated financial statements. While the amounts applicable to PRL’s northeast Alberta properties for certain revenues, royalties, expenses, assets and liabilities could be derived directly from the accounting records of PRL, it was necessary to allocate certain other items between PRL’s core areas. In the opinion of management, the consolidated balance sheet and statements of earnings include all adjustments necessary for the fair presentation of the transactions in accordance with Canadian GAAP.

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

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 proven recoverable reserves of each producing property or project. Depreciation of other equipment is provided on a declining balance method at rates varying from 20 to 30 percent.

The net amount at which petroleum and natural gas costs on a property or project 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 proven and probable reserves are subject to uncertainty associated with the quantity of oil and gas reserves, future production rates, commodity prices and other factors.

Prior to January 1, 2003, the net amount at which petroleum and natural gas costs on a property or project were carried was subject to a different cost-recovery test. Any impairment loss was the difference between the carrying value of the asset and its recoverable amount (undiscounted). This change has been adopted retroactively but had no effect on these consolidated financial statements.

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 2.5 percent - 20 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** Per Unit amounts for all periods prior to March 31, 2003 have been presented on a pro-forma basis as if the Trust Units outstanding at March 31, 2003 were all outstanding for each period shown (see Note 1). Basic earnings per Unit were calculated using the weighted average number of Trust Units outstanding during the year (2003 - 42,597,280;

2002 – 39,638,376). The Trust uses the treasury stock method where only "in the money" dilutive instruments impact the diluted calculations. In computing diluted earnings from operations per unit 640,751 net Units were added to the weighted average number of Trust Units outstanding during the twelve-month period ended December 31, 2003 (2002 – nil net Units) for the dilutive effect of Incentive Rights.

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 gain and losses are reflected in earnings in they period in which they arise.

f) **Financial Instruments** Financial instruments are utilized by PET to manage its exposure to commodity price fluctuations, foreign currency and interest rates. PET's policy is not to utilize financial instruments for trading or speculative purposes.

PET formally documents relationships between hedging instruments and hedged items, as well as 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. PET also formally assesses, both at the hedge's inception and on an ongoing basis, whether the derivatives that are used in hedging transactions are highly effective in offsetting changes in fair value or cash flows of hedged items

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.

g) **Income Taxes** For periods prior to 2003, income tax expense has been recorded using the average tax rate applicable to PRL. As PRL's northeast Alberta assets generated cash flow significantly in excess of capital investment, there were assumed to be no tax pools available to defer these tax obligations. As a result, all taxes are assumed to be cash tax obligations and to have been paid during the year on an installment basis.

The Trust, and its 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 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 in these consolidated financial statements. The Administrator has no tax balances.

h) **Unit Incentive Plan** The Trust has a Unit Incentive Plan as described in Note 8. Effective for fiscal years beginning on or after January 1, 2002, the Trust adopted the recommendations of the CICA on accounting for stock-based compensation which apply to new Incentive Rights granted on or after January 1, 2002. The Trust has elected to measure compensation cost to employees based on the settlement method at the date of the grant and recognize that cost over the vesting period. As the exercise price of the Incentive Rights granted approximates the market price of the Trust Units at the time of the grant date, no compensation cost has been provided in the statement of earnings.

The exercise price of the Incentive Rights granted under the Trust's Unit Incentive Plan may be reduced in future periods in accordance with the terms of the Incentive Rights plan. The amount of the reduction cannot be reasonably estimated as it is dependent upon a number of factors including, but not limited to, future prices received on the sale of oil and natural gas, future production of oil and natural gas, determination of amounts to be withheld from future distributions to fund capital expenditures and the purchase and sale of property, plant and equipment. Therefore, it is not possible to determine a fair value for the Incentive Rights granted under the plan.

Compensation costs for pro forma disclosure purposes have been determined based on the excess of the Trust Unit price over the adjusted exercise price (see Note 8) of the Incentive Rights at the date of the financial statements. For the year ended December 31, 2003, net earnings would be reduced by $2.4 million ($0.05 per Trust Unit, basic and diluted) for the estimated compensation cost associated with the Incentive Rights granted under the Rights Plan on or after January 1, 2002. All Incentive Rights were issued during 2003; as a result, the 2002 net earnings was not affected by compensation costs.

i) **Measurement Uncertainty** The preparation of financial statements in conformity with Canadian generally accepted accounting principles 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. 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.

3. CHANGE IN ACCOUNTING POLICY

Asset Retirement Obligation

In December 2003, the Trust adopted CICA Handbook Section 3110 “Asset Retirement Obligations”. This Change in accounting policy has been applied retroactively with restatement of prior periods presented for comparative purposes.

Previously, the Trust recognized a provision for future site reclamation and abandonment costs calculated on the unit-of-production method over the life of the natural gas properties based on the total estimated proved reserves and an estimated future liability.

As a result of this change, net earnings for the year ended December 31, 2003 decreased by $0.9 million (2002 - $1.6 million). The obligation increased by $11.9 million (2002 - $12.9 million) and property, plant and equipment, net of accumulated depletion increased by $7.4 million (2002 - $9.3 million). Opening 2003 accumulated earnings decreased by $3.6 million (2002 - $2.0 million) to reflect the cumulative impact of depletion expense, net of the cumulative site restoration provision on the asset retirement obligation recorded retroactively.

4. BUSINESS COMBINATION

On November 18, 2003, the Trust and Epact Exploration Ltd. (“Epact”) jointly announced that they had entered into an agreement pursuant to which the Trust would make an offer to purchase all of the issued and outstanding common shares of Epact for cash consideration of $1.57 per share or approximately $13.2 million, including acquisition costs. This transaction has been accounted for using the purchase method as of the closing date of November 18, 2003.

The following table summarizes the value of the assets acquired and liabilities assumed at the date of acquisition:

Working capital deficiency	$	(4,768)
Property, plant and equipment		18,453
Asset retirement obligation		(423)
	$	13,262

5. PROPERTY, PLANT AND EQUIPMENT

	December 31, 2003	December 31, 2002
Petroleum and Natural Gas Properties	$ 587,388	$ 517,562
Corporate Assets	3,585	2,828
Adjustment to Net Book Value (Note 1)	(16,172)	1,317
	574,801	521,707
Accumulated Depletion and Depreciation	(332,846)	(260,371)
	$ 241,955	$ 261,336

At December 31, 2003 the Trust recorded a write-down to property, plant and equipment in the amount of $9.8 million (see Note 11).

Included in the Trust's property, plant and equipment is $7.4 million ($9.3 million in 2002), net of accumulated depletion relating to the adoption of asset retirement obligations (Note 3).

Property, plant and equipment costs included $46.8 million (2002 - $48.5) currently not subject to depletion.

On January 5, 2004 PET closed the acquisition of producing natural gas properties at Marten Hills, Alberta for $30.3 million. This acquisition was financed from existing credit facilities.

6. BANK AND OTHER DEBT

PET has a revolving credit facility with a syndicate of Canadian Chartered Banks. As at the date of the audit report the revolving credit facility had a borrowing base of $100 million. The facility consists of a demand loan of $90 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 $1.7 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.

On February 4, 2003 PET issued a promissory note in the amount of $34.2 million to PRL in relation to the acquisition of certain assets in northeast Alberta. Subsequently this promissory note was extinguished through the issue of Trust Units (Note 7).

On February 3, 2003 PET issued a promissory note in the amount of $30.0 million to PRL in relation to the acquisition of certain assets in northeast Alberta. Subsequently this promissory note was extinguished through the utilization of bank facilities.

On July 1, 2002 PET issued a promissory note pursuant to the acquisition of assets from a subsidiary of PRL. This promissory note accrued interest at a rate of prime plus 0.25 percent. The promissory note was repaid in full on February 3, 2003. All interest accrued on the promissory note was paid at the time the promissory note was extinguished.

7. UNITHOLDERS' CAPITAL

a) **Authorized**

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

b) **Issued and Outstanding**

The following is a summary of changes in Unitholders' Capital during the year ended December 31, 2003:

Trust Units	Number Of Units	Amount
Balance, December 31, 2002	1	$ 100
Units Issued on Settlement of Promissory Note (Notes 1 and 6)	6,636,045	34,152,000
Units Issued on Settlement of Promissory Note (Notes 1 and 6)	3,273,721	16,848,000
Units Cancelled after Declaration of Dividend by Paramount Resources Limited	(173)	(874)
Units Issued Pursuant to Rights Offering (Note1)	29,728,782	150,130,349
Units Issued Pursuant to Unit Offering (Note 1)	5,000,000	63,250,000
Trust Unit Issue Costs	-	(4,361,575)
Balance, December 31, 2003	44,638,376	$ 260,018,000

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.

8. UNIT INCENTIVE PLAN

PET has adopted a 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 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 (the "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 holder of the Incentive Rights may elect to reduce the strike price of the Incentive Rights (the "Strike Price"), such reduction determined 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 fixed assets on its balance sheet at each calendar quarter end.

The Strike Price will be adjusted on a quarterly basis and in no case may it be reduced to less than $0.001 per Trust Unit.

PET has granted 1,108,000 Incentive Rights to purchase PET Trust Units to directors, officers and employees of the Administrator of which 928,000 were granted at $5.05 and 180,000 were granted at $11.10 to $11.15 per Incentive Right.

For purposes of Canadian generally accepted accounting principles, PET will account for the Incentive Rights granted to employees or directors of PET and its subsidiaries by the settlement method under which no amount will be recorded at the time the Incentive Rights are granted. Proceeds received on the exercise of the rights will be recorded to Unitholders' Capital.

The Incentive Rights will only be dilutive to the calculation of earnings per Trust Unit if the exercise price is below the fair value of the Unit.

At December 31, 2003 a total of 3,963,838 units had been reserved under the Unit Incentive Plan. As at December 31, 2003 no Incentive Rights granted under the Unit Incentive Plan had vested.

Incentive Rights	**2003**	
	Average grant price	**Incentive rights**
Balance, beginning of year	-	-
Granted	**$ 6.04**	**1,108,000**
Exercised	**-**	**-**
Cancelled	**-**	**-**
Balance, end of year	**$ 6.04**	**1,108,000**
Incentive Rights exercisable, end of year	**-**	**-**

The following summarizes information about Incentive Rights outstanding at December 31, 2003 assuming the reduced Strike Price described above:

Range of Exercise Prices	**Number outstanding at December 31, 2003**	**Weighted average contractual life (years)**	**Weighted average exercise price/ Right**	**Number exercisable at December 31, 2003**	**Weighted average exercise price/Right**
$2.99	928,000	4	$ 2.99	**-**	**-**
$11.10-$11.15	180,000	5	$ 11.12	**-**	**-**

9. ASSET RETIREMENT OBLIGATIONS

The total future asset retirement obligation was estimated based on the Trust'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. The Trust has estimated the net present value of its total asset retirement obligations to be $21.7 million as at December 31, 2003 based on an undiscounted total future liability of $46 million. These payments are expected to be made over the next 25 years with the majority of costs incurred between 2010 and 2015. The Trust used a credit adjusted risk free rate of 6.25% to calculate the present value of the asset retirement obligation.

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

	2003	**2002**
Obligation, beginning of year	$ 20,039	$ 18,404
Increase in obligation during the year	423	472
Expenditures incurred during the year	-	-
Accretion expense	1,239	1,163
Obligation, end of year	$ 21,701	$ 20,039

10. FINANCIAL INSTRUMENTS

The Trust's financial instruments included in the Consolidated 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, 2003 and 2002 due to their short-term nature.

Natural gas commodity price hedges

At December 31, 2003, the Trust has entered into financial forward sales arrangements summarized as follows:

Volumes at AECO (Gigajoules/day) ("GJ/d")	Price ($/GJ)	Term
45,000 GJ/d	$ 6.30	January 2004 – March 2004
25,000 GJ/d	$ 5.40	April 2004 – October 2004
7,500 GJ/d	$ 5.00 to 7.10	April 2004 – December 2004

Had these contracts been settled on December 31, 2003, using prices in effect at that time, the mark-to-market loss would have totaled $4.0 million.

11. GAS OVER BITUMEN ISSUE

The Alberta Energy and Utilities Board ("AEUB" or the "Board") issued General Bulletin ("GB") 2003-28 (the "Bulletin") on July 22, 2003. The AEUB continues to consider that gas production in pressure communication with associated potentially recoverable bitumen places future bitumen recovery at an unacceptable risk. On January 26, 2004, the AEUB Staff Submission Group ("SSG") released their recommendations for the shut-in of producing wells with total average daily production of 135 MMcf/d as of August 31, 2003 or approximately one percent of the natural gas production of the Province of Alberta. Pursuant to Interim Shut-in Order 03-001, approximately 95 MMcf/d was shut-in by Industry on September 1, 2003 while a shut-in date has not been announced for the remaining 40 MMcf/d recommended for shut-in by the SSG. A total of 24.1 MMcf/d of PET production was recommended for shut-in by the SSG which includes 7.6 MMcf/d of the gas shut-in on September 1, 2003 and an additional 16.5 MMcf/d of PET's production which was previously exempted from Interim Shut-in Order 03-001.

AEUB Interim Hearings with respect to this matter are scheduled to begin on March 10, 2004. On February 27, the Alberta Court of Appeal granted a stay of the AEUB hearing process to the extent that it applies to wells for which the productive status was previously determined under AEUB Decision 2003-23 following the Chard/Leismer Hearing. This should exclude 0.7 MMcf/d of PET production from the current proceedings. PET anticipates that a similar exclusion will be put in effect for wells previously ruled on in AEUB Decision 2000-22 following the Surmont Hearing. This should exclude an additional 0.8 MMcf/d of PET production from the March proceedings. The Alberta Court of Appeal declined to grant a stay of the March interim hearings; however, PET and others have been granted Leave to Appeal the entire GB 2003-28 process. A date for the hearing of that appeal has not been set.

At December 31, 2003 PET recorded a write-down of property, plant and equipment of $9.8 million (Note 5). This amount arose in connection with the increase in capital assets related to the adoption of asset retirement obligations (Note 3), revisions to PET's reserves and adjustments to estimates of future cash flows related to the gas/bitumen issue. No future compensation with respect to the gas/bitumen issue for any shut-in production beyond the current interim financial assistance of $0.60 per Mcf on current or future foregone production was included in the determination of this write-down. To the extent that circumstances including volumes of gas shut-in or finalization of compensation arrangements change, further adjustments to the carrying amount of PET's property, plant and equipment may be required. Such adjustments relate to prescribed determinations under the successful efforts method of accounting and should not be taken to represent indications of the fair market value of PET's assets or the possible impairment of such value.

Until the AEUB determines the final productive status of the wells, PET cannot accurately estimate the amount of production that may remain shut-in, if any, and for what duration. The amount and timing of compensation for having to shut in such production is also not determinable at this time. To December 31, 2003, PET had incurred $0.7 million in legal and other costs with respect to the gas over bitumen issue. PET will continue to pursue all avenues to defend its gas production and Unitholder value.