PEYTO

Energy Trust

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Interim Report
for the nine months ended September 30, 2010

Highlights

	3 Months Ended September 30		%	9 Months Ended September 30		%
	2010	2009	Change	**2010**	2009	Change
Operations						
Production						
Natural gas (mcf/d)	**122,717**	89,259	*37%*	**113,093**	91,791	*23%*
Oil & NGLs (bbl/d)	**3,322**	2,916	*14%*	**3,373**	2,962	*14%*
Thousand cubic feet equivalent (mcfe/d @ 1:6)	**142,651**	106,755	*34%*	**133,328**	109,565	*22%*
Barrels of oil equivalent (boe/d @ 6:1)	**23,775**	17,792	*34%*	**22,221**	18,261	*22%*
Product prices						
Natural gas ($/mcf)	**5.16**	5.74	*(10)%*	**5.55**	6.54	*(15)%*
Oil & NGLs ($/bbl)	**59.66**	51.06	*17%*	**64.70**	46.30	*40%*
Operating expenses ($/mcfe)	**0.34**	0.41	*(17)%*	**0.37**	0.43	*(14)%*
Transportation ($/mcfe)	**0.14**	0.11	*27%*	**0.13**	0.11	*18%*
Field netback ($/mcfe)	**4.83**	5.22	*(7)%*	**5.13**	5.58	*(8)%*
General & administrative expenses ($/mcfe)	**0.12**	0.15	*(20)%*	**0.12**	0.19	*(37)%*
Interest expense ($/mcfe)	**0.39**	0.46	*(15)%*	**0.40**	0.40	-
Financial ($000, except per unit)						
Revenue	**76,450**	60,860	*26%*	**230,794**	201,299	*15%*
Royalties	**6,800**	4,507	*51%*	**25,694**	18,214	*41%*
Funds from operations	**56,743**	45,263	*25%*	**167,717**	149,397	*12%*
Funds from operations per unit	**0.47**	0.39	*21%*	**1.41**	1.37	*3%*
Total distributions	**43,875**	41,371	*6%*	**128,969**	121,891	*6%*
Total distributions per unit	**0.36**	0.36	-	**1.08**	1.12	*(4)%*
Payout ratio	**77**	91	*(15)%*	**77**	82	*(6)%*
Earnings	**32,567**	26,976	*22%*	**94,138**	119,547	*(21)%*
Earnings per diluted unit	**0.27**	0.23	*17%*	**0.79**	1.10	*(28)%*
Capital expenditures	**64,123**	28,725	*123%*	**150,923**	46,432	*225%*
Weighted average trust units outstanding	**121,765,712**	114,920,194	*6%*	**118,803,946**	109,085,029	*9%*
As at September 30						
Net Debt				**457,959**	423,964	*8%*
Unitholders' equity				**699,576**	623,883	*12%*
Total assets				**1,377,935**	1,240,770	*11%*

	3 Months Ended September 30		9 Months Ended September 30	
($000)	**2010**	2009	**2010**	2009
Cash flows from operating activities	**48,681**	49,827	**156,986**	152,121
Change in non-cash working capital	**5,129**	(5,726)	**(704)**	(4,500)
Change in provision for performance based compensation	**2,933**	1,162	**11,435**	1,776
Funds from operations	**56,743**	45,263	**167,717**	149,397
Funds from operations per unit	**0.47**	0.39	**1.41**	1.37

(1) Funds from operations - Management uses funds from operations to analyze the operating performance of its energy assets. In order to facilitate comparative analysis, funds from operations is defined throughout this report as earnings before performance based compensation, non-cash and non-recurring expenses. Management believes that funds from operations is an important parameter to measure the value of an asset when combined with reserve life. Funds from operations is not a measure recognized by Canadian generally accepted accounting principles ("GAAP") and does not have a standardized meaning prescribed by GAAP. Therefore, funds from operations, as defined by Peyto, may not be comparable to similar measures presented by other issuers, and investors are cautioned that funds from operations should not be construed as an alternative to net earnings, cash flow from operating activities or other measures of financial performance calculated in accordance with GAAP. Funds from operations cannot be assured and future distributions may vary.

Report from the president

Peyto Energy Trust ("Peyto" or the "Trust") is pleased to present the operating and financial results for the third quarter of the 2010 fiscal year. The Trust grew production 34% year over year or 25% per unit since Q3 2009 while generating third quarter operating margins of 74%(1) and profit margins of 43%(2). Third quarter 2010 highlights were as follows:

- Production grew from 107 MMcfe/d (17,792 boe/d) in Q3 2009 to 143 MMcfe/d (23,775 boe/d) in Q3 2010, as a result of the continued development of Peyto's Deep Basin tight gas plays. This equates to a 25% increase per unit, a 34% increase on an absolute basis, and a 36% increase in production per unit, debt adjusted (3).

- Funds from operations ("FFO") increased 25% from $45.3 million in Q3 2009 to $56.7 million in Q3 2010 in response to the increased production volumes despite a 6% drop in realized commodity prices from $6.20/mcfe to $5.83/mcfe respectively (including hedging gains). FFO per unit were up 21% to $0.47/unit.

- Industry leading operating costs were reduced 17% to $0.34/mcfe ($2.04/boe) from Q3 2009 or $0.48/mcfe ($2.86/boe) including transportation. Corporate netbacks were 6% lower at $4.32/Mcfe ($25.94/boe), or 74% of revenue.

- Capital expenditures of $64.1 million (net of $2.0 million in Drilling Royalty Credits) were invested in the quarter, up 123% from $28.7 million in Q3 2009. A total of 9 net wells were drilled during the quarter.

- Earnings of $32.6 million ($0.27/unit) were generated in the quarter and distributions to unitholders were $43.9 million ($0.36/unit).

Third Quarter 2010 in Review

In the third quarter, Peyto continued to focus on maintaining its low cost structure. This unique cost structure ensures the Trust delivers high netbacks, even at the bottom of the natural gas price cycle, and allows Peyto to develop its assets when demand for services are low and input costs are reasonable. Peyto takes advantage of this counter cyclical investment approach with the confidence that strong returns are being generated, even at current gas prices. The Trust had a very active third quarter, investing 123% more than Q3 2009, as last year's successful horizontal pilot programs evolved into multi-well development programs. By the end of the third quarter, the 2010 capital program was responsible for approximately 58 MMcfe/d (9,700 boe/d) of new production or 38% of total production. Operating costs continued to decline, with higher production from new wells increasing facility utilizations. Peyto's facility and pipeline infrastructure was expanded in the quarter, to accommodate the increased production volumes. Peyto also increased its core area prospect inventory with the purchase of new Deep Basin lands, bringing total undeveloped land purchases for 2010 to 50,400 net acres (79 sections). Alberta spot natural gas price averaged $3.36/GJ in the third quarter, up 20% from $2.79/GJ in the third quarter 2009 but lower than the $3.69/GJ experienced last quarter. Peyto's high heat content and liquids rich, natural gas production garnered $4.85/Mcfe before hedging and $5.83/Mcfe after hedging. Continued strong financial and operating performance resulted in an annualized 19% Return on Equity (ROE) and 11% Return on Capital Employed (ROCE).

(1) Operating Margin is defined as Funds from Operations divided by Revenue before Royalties but including realized hedging gains (losses).
(2) Profit Margin is defined as Net Earnings for the quarter divided by Revenue before Royalties but including realized hedging gains (losses).
(3) Per unit results are adjusted for changes in net debt and equity. Net debt is converted to equity using a Sept. 30 unit price of $15.54 for 2010 and $10.69 for 2009.
Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl). Natural gas liquids and oil volumes in barrel of oil (bbl) are converted to thousand cubic feet equivalent (mcfe) using a ratio of one (1) barrel of oil to six (6) thousand cubic feet. This could be misleading if used in isolation as it is based on an energy equivalency conversion method primarily applied at the burner tip and does not represent a value equivalency at the wellhead.

Capital Expenditures

Peyto had a very active third quarter, investing $64.1 million (net of $2.0 million in Drilling Royalty Credits) in the ongoing development of its Deep Basin core areas. The Trust spent $56.7 million on new drilling, completions and well tie-ins, $4.6 million on plant expansions and $4.8 million on the purchase of new opportunities in the form of undeveloped land.

During the quarter, 10 gross (9 net) wells were drilled, including 9 horizontal wells and one multi-zone vertical well. In total, 16 gross (15 net) zones were completed and 17 gross (16 net) zones brought on stream.

The Peyto Nosehill gas plant underwent an expansion in the quarter, increasing the capacity from 30 to 50 MMcf/d. As well, a 20 km, 8" pipeline was constructed to connect new Obed volumes to the Wildhay gas plant.

The Trust was active in the quarter purchasing new crown mineral leases with 28,000 net acres (43.75 sections) of new lands acquired at an average cost of $144/acre. Drilling locations have been identified on these new lands, which are all adjacent to Peyto's core areas, and will benefit from the Trust's existing facility infrastructure. So far in 2010, total land purchases equate to a 30% increase in prospective undeveloped land.

Financial Results

In the third quarter 2010, the Trust realized natural gas prices of $4.02/mcf, from average Alberta gas prices of $3.47/GJ, while realizing $59.66/bbl for its natural gas liquids blend of condensate, propane and butane. This liquids price represents 80% of the average Edmonton light oil price of $74.46/bbl. The natural gas and liquids streams, split 86% and 14% of production respectively, combined for an unhedged revenue stream of $4.85/mcfe or $29.10/boe. Realized hedging gains improved revenues by $0.98/mcfe ($5.88/boe). Total cash costs of $1.51/mcfe, made up of $0.52/mcfe for royalties, $0.34/mcfe for operating costs, $0.14/mcfe for transportation costs, $0.12/mcfe for G&A, and $0.39/mcfe for interest, reduced the realized revenue to $4.32/mcfe or $25.94/boe. This cash netback of $4.32/mcfe equates to 74% of revenue.

DD&A of $1.69/mcfe, as well as a provision for future performance based compensation and future income tax, reduced funds from operations to yield earnings of $2.48/mcfe or a 43% profit margin.

Unitholder participation in Peyto's Distribution Re-Investment Plan ("DRIP") and Optional Trust Unit Purchase Plan ("OTUPP") resulted in the issuance of 1,035,384 units at an average price of $14.01 for net proceeds of $14.5 million during the third quarter.

Marketing

Natural gas prices in the third quarter 2010 continued to reflect the abundance of supply in North America even with increased weather related demand. Drilling activity for natural gas remained high despite these lower prices which further increased this over-supplied situation. As a result, Canadian natural gas prices remained at historical low levels averaging $3.36/GJ for daily AECO spot price. Meanwhile, US natural gas prices declined 20% throughout the quarter and are now approaching Canadian gas price levels. Peyto's strategy of forward natural gas sales resulted in a realized Q3 2010 hedging gain of $12.9 million. This compares with a gain of $11.4 million in the second quarter 2010 and a $20.0 million gain in Q3 2009.

As at September 30, 2010, the Trust had committed to the future sale of 23,280,000 gigajoules (GJ) of natural gas at an average price of $5.07/GJ or $5.93/mcf. Had these contracts been closed on September 30, 2010, the Trust would have realized a gain in the amount of $41.5 million.

Activity Update

At this time, production has already reached the year-end target of 28,000 boe/d as new horizontal well completions continue to meet or exceed expectations. Peyto is currently running 8 drilling rigs and expects to drill another 12 gross (11.5 net) horizontal wells this year. In addition to the 4 gross (4 net) horizontal wells that are currently being completed and tied in, the majority of these 12 new wells are also expected to be completed and on-stream before the end of the fourth quarter.

During the fourth quarter, another compressor will be installed at each of Peyto's Nosehill and Wildhay gas plants, increasing processing capacity to 60 MMcf/d and 30 MMcf/d respectively. By the end of 2010, Peyto will have added over 70 MMcf/d of processing capacity for a total capital investment of $15 million. The combination of this facility work and the new well activity is expected to increase Peyto's net production beyond 30,000 boe/d by year-end.

Corporate Conversion

On November 8, 2010, an Information Circular was mailed to unitholders of record, as at November 5, 2010, outlining the process for conversion of the Trust to corporate form. The conversion will be effected pursuant to a unitholder and court approved Plan of Arrangement, with a unitholder meeting planned for December 8, 2010. The effective date of the conversion is expected to be December 31, 2010. For the remainder of 2010, the Trust plans on maintaining distributions at $0.12/unit/month, at which point distributions will be terminated and a $0.06/month dividend will be introduced. This dividend level is confirmed for the first quarter of 2011 and future dividend levels will be set by the Board of Directors of Peyto in early 2011.

Upon conversion to a corporation, The Board of Directors of Peyto has decided not to offer a Dividend Re-Investment Plan. This decision is predicated on the fact that a significant portion of Peyto unitholders, who are non-Canadian unitholders, cannot participate.

Outlook

Peyto is pleased to announce the appointment of David Thomas to the position of Vice-President, Exploration. Dave has been a senior exploration geologist with Peyto since 2005 and continues to bring a wealth of Deep Basin expertise to Peyto's ongoing exploration and development programs.

Peyto has already reached its previously announced year end production target of 28,000 boe/d and is now on track to exit 2010 at or above 30,000 boe/d. The team is refining the details of the 2011 capital program which is expected to be between $250 to $275 million. This program will target a blend of horizontal multi-stage frac well development amongst existing successful play types and new tests of formations across Peyto's core areas. The team's hard work and focus on cost control allows Peyto to continue to concentrate on low cost, high netback, liquids rich, natural gas prospects. As always, Peyto will continue to innovate and expand its opportunity base beyond the existing seven year inventory.

Unitholders are encouraged to follow the progress of Peyto's 2010 capital program with monthly president's reports and updated presentations on the Peyto website.

Darren Gee
President and CEO
November 9, 2010

Management's discussion and analysis

This Management's Discussion and Analysis ("MD&A") should be read in conjunction with the unaudited interim consolidated financial statements for the period ended September 30, 2010 and the audited consolidated financial statements of Peyto Energy Trust (the "Trust" or "Peyto") for the year ended December 31, 2009. The consolidated financial statements have been prepared in accordance with Canadian generally accepted accounting principles ("GAAP").

This discussion provides management's analysis of Peyto's historical financial and operating results and provides estimates of Peyto's future financial and operating performance based on information currently available. Actual results will vary from estimates and the variances may be significant. Readers should be aware that historical results are not necessarily indicative of future performance. This MD&A was prepared using information that is current as of November 9, 2010. Additional information about Peyto, including the most recently filed annual information form is available at www.sedar.com.

Certain information set forth in this MD&A, including management's assessment of the Trust's future plans and operations, contains forward-looking statements. By their nature, forward-looking statements are subject to numerous risks and uncertainties, some of which are beyond these parties' control, including the impact of general economic conditions, industry conditions, volatility of commodity prices, currency fluctuations, imprecision of reserve estimates, environmental risks, competition from other industry participants, the lack of availability of qualified personnel or management, stock market volatility and ability to access sufficient capital from internal and external sources. Readers are cautioned that the assumptions used in the preparation of such information, although considered reasonable at the time of preparation, may prove to be imprecise and, as such, undue reliance should not be placed on forward-looking statements. Peyto's actual results, performance or achievement could differ materially from those expressed in, or implied by, these forward-looking statements and, accordingly, no assurance can be given that any of the events anticipated by the forward-looking statements will transpire or occur, or if any of them do so, what benefits that Peyto will derive there from.

All references are to Canadian dollars unless otherwise indicated. Natural gas liquids ("NGL") and oil volumes are recorded in barrels of oil (bbl) and are converted to one thousand cubic feet equivalent (mcfe) using a ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl). Natural gas volumes recorded in thousand cubic feet (mcf) are converted to barrels of oil equivalent (boe) using the ratio of six (6) thousand cubic feet to one (1) barrel of oil (bbl).

Corporate Conversion

On September 28, 2010, Peyto announced plans to convert the Trust to a corporation on December 31, 2010. On November 1, 2010 the Board of Directors of Peyto Energy Administration Corp. approved the Plan of Arrangement, subject to unitholder approval. If approved, this plan will result in the reorganization of the Trust into a public oil and gas exploration and development company that will operate under the name "Peyto Exploration & Development Corp." ("New Peyto") and will own all of the existing assets and assume all of the existing liabilities of the Trust and its subsidiaries. The board of directors and senior management of New Peyto will be comprised of the current members of the board of directors of Peyto Energy Administration Corp., the current administrator of the Trust and senior management of the Corporation. The conversion will not trigger any change of control or other termination payments to management pursuant to any employment agreements or similar arrangements within the Trust. The board of directors of Peyto Administration Corp. believes that conversion to a corporate structure at this time will best enable New Peyto to execute its strategic plan and better position New Peyto to deliver strong growth and capital appreciation for its shareholders over the long-term. Unitholders will receive, for each Trust Unit held, one common share of New Peyto. The conversion of the Trust to a corporate structure is intended to be a tax deferred transaction for Canadian and United States federal income tax purposes.

It is the current intention of the Trust that New Peyto will, subject to applicable laws, establish a dividend policy of paying monthly dividends to the holders of New Peyto shares, with the initial monthly dividend presently anticipated to be $0.06 per New Peyto share. This dividend level has been set for the first quarter of 2011. As a result, the first dividend of New Peyto that all New Peyto shareholders will be eligible to receive is the dividend anticipated to be paid to New Peyto shareholders of record on January 31, 2011, which is anticipated to be paid on February 15, 2011. The board of directors of New Peyto will review the dividend policy from time to time. The actual amount distributed will be at the sole discretion of the board of directors of New Peyto.

A special meeting of unitholders of Peyto Energy Trust will be held in the main boardroom at Burnet, Duckworth & Palmer LLP, 1400, 350 – 7th Avenue S.W., Calgary, Alberta at 10:00 a.m. (Calgary time) on December 8, 2010 to approve this Plan of Arranement.

Peyto is a Canadian energy trust involved in the development and production of natural gas in Alberta's deep basin. As at December 31, 2009, the total Proved plus Probable reserves were 1.2 trillion cubic feet equivalent (200 million barrels of oil equivalent) as evaluated by the independent petroleum engineers. Production is weighted approximately 85% natural gas and 15% natural gas liquids and oil.

The Peyto model is designed to deliver a superior total return and, over time, growth in value, assets, production and income, all on a debt adjusted per unit basis. The model is built around three key principles:

- Use technical expertise to achieve the best return on capital employed, through the development of internally generated drilling projects.
- Maintain a payout ratio designed to efficiently fund a growing inventory of drilling projects.
- Build an asset base which is made up of high quality long life natural gas reserves.

Operating results over the last eleven years indicate that these principles have been successfully implemented. This business model makes Peyto a truly unique energy trust.

QUARTERLY FINANCIAL INFORMATION

	2010				**2009**			**2008**
($000 except per unit amounts)	**Q3**	Q2	Q1	Q4	Q3	Q2	Q1	Q4
Total revenue (net of royalties)	**69,650**	64,649	70,801	64,761	56,353	56,598	70,133	79,612
Funds from operations	**56,743**	52,415	58,559	53,302	45,263	45,527	58,607	67,354
Per unit – basic and diluted	**0.47**	0.44	0.51	0.46	0.39	0.43	0.55	0.64
Earnings (loss)	**32,567**	24,696	36,874	33,035	26,976	29,189	63,574	50,711
Per unit – basic and diluted	**0.27**	0.21	0.32	0.28	0.24	0.28	0.60	0.48
Distributions	**43,875**	43,622	41,470	41,371	41,371	39,211	41,309	47,664
Per unit – diluted	**0.36**	0.36	0.36	0.36	0.36	0.37	0.39	0.45

Funds from Operations

"Funds from operations" is a non-GAAP measure which represents cash flows from operating activities before changes in non-cash operating working capital and provision for future performance based compensation. Management considers funds from operations and per unit calculations of funds from operations to be key measures as they demonstrate the Trust's ability to generate the cash necessary to pay distributions, repay debt and make capital investments. Management believes that by excluding the temporary impact of changes in non-cash operating working capital, funds from operations provides a useful measure of the Trust's ability to generate cash that is not subject to short-term movements in operating working capital. The most directly comparable GAAP measure is cash flows from operating activities.

RESULTS OF OPERATIONS

Production

	Three Months ended September 30		Nine Months ended September 30	
	2010	2009	**2010**	2009
Natural gas (mmcf/d)	**122.7**	89.3	**113.1**	91.8
Oil & natural gas liquids (bbl/d)	**3,322**	2,916	**3,373**	2,962
Barrels of oil equivalent (boe/d)	**23,775**	17,792	**22,221**	18,261
Million cubic feet equivalent (mmcfe/d)	**142.7**	106.8	**133.3**	109.6

Natural gas production averaged 122.7 mmcf/d in the third quarter of 2010, 37 percent higher than the 89.3 mmcf/d reported for the same period in 2009. Oil and natural gas liquids production averaged 3,322 bbl/d, an increase of 14 percent from 2,916 bbl/d reported a year earlier. Third quarter total production increased 34 percent from 106.8 mmcfe/d to 142.7 mmcfe/d. The production increases are attributable to Peyto's increased capital program and resulting production additions.

Commodity Prices

	Three Months ended September 30		Nine Months ended September 30	
	2010	2009	**2010**	2009
Natural gas ($/mcf)	**4.02**	3.31	**4.57**	4.51
Hedging – gas ($/mcf)	**1.14**	2.43	**0.98**	2.03
Natural gas – after hedging ($/mcf)	**5.16**	5.74	**5.55**	6.54
Oil and natural gas liquids($/bbl)	**59.66**	51.06	**64.70**	46.30
Total Hedging ($/mcfe)	**0.98**	2.04	**0.73**	1.70
Total Hedging ($/boe)	**5.88**	12.23	**4.97**	10.21

Peyto's natural gas price, before hedging gains, averaged $4.02/mcf during the third quarter of 2010, a 21 percent increase from $3.31/mcf reported for the same period in 2009. Oil and natural gas liquids prices averaged $59.66/bbl, an increase of 17 percent from $51.06/bbl a year earlier. Hedging activity for the third quarter of 2010 accounted for 17% of Peyto's achieved price.

Revenue

	Three Months ended September 30		Nine Months ended September 30	
($000)	**2010**	2009	**2010**	2009
Natural gas	**45,341**	27,144	**141,098**	112,946
Oil and natural gas liquids	**18,237**	13,697	**59,571**	37,444
Hedging gain (loss)	**12,872**	20,019	**30,124**	50,909
Total revenue	**76,450**	60,860	**230,793**	201,299

For the three months ended September 30, 2010, revenue increased 26 percent to $76.5 million from $60.9 million for the same period in 2009. The increase in revenue for the period was a result of increased production volumes and higher realized oil and NGL prices offset by lower realized natural gas prices as detailed in the following table:

	Three Months ended September 30			Nine Months ended September 30		
	2010	2009	**$million**	2010	2009	**$million**
Total Revenue, September 30, 2009			**60.9**			**201.3**
Revenue change due to:						
Natural gas						
Volume (mmcf)	11,290	8,212	**17.7**	30,874	25.059	**38.0**
Price ($/mcf)	$5.16	$5.74	**(6.6)**	$5.55	$6.54	**(30.6)**
Oil & NGL						
Volume (mbbl)	306	268	**1.9**	921	809	**5.2**
Price ($/bbl)	$59.66	$51.06	**2.6**	$64.70	$46.30	**16.9**
Total Revenue, September 30, 2010			**76.5**			**230.8**

Royalties

Royalties are paid to the owners of the mineral rights with whom leases are held, including the provincial government of Alberta. Alberta gas crown royalties are invoiced on the Crown's share of production based on a monthly established Alberta Reference Price. The Alberta Reference Price is a monthly weighted average price of gas consumed in Alberta and gas exported from Alberta reduced for transportation and marketing allowances.

	Three Months ended September 30		Nine Months ended September 30	
($000 except per unit amounts)	**2010**	2009	**2010**	2009
Royalties	**6,800**	4,507	**25,693**	18,214
% of sales before hedging	**12.2**	11.0	**12.8**	12.1
% of sales after hedging	**8.9**	7.4	**11.1**	9.0
$/mcfe	**0.52**	0.46	**0.71**	0.61
$/boe	**3.11**	2.75	**4.24**	3.65

For the third quarter of 2010, royalties averaged $0.52/mcfe or approximately 8.9 percent of Peyto's total petroleum and natural gas sales.

Substantially all of the Trust's production is in Province of Alberta. Under the Alberta Royalty Framework ("ARF") the Crown royalty rate varies with production rates and commodity prices. The royalty rate expressed as a percentage of sales revenue will fluctuate from period to period due to the fact that the Alberta Reference Price can differ significantly from the commodity prices realized by the Trust and that hedging gains and losses are not subject to royalties.

In addition to the basic underlying royalty structure (the ARF), Alberta has instituted additional features that impact the royalty paid on gas, particularly for newly drilled wells. These additional features include:

1. A drilling royalty credit program that is presently active but will terminate at the end of March, 2011. Under this program credits are earned at a rate of $200 per meter of newly drilled well depth and can be applied with certain limitations to the earning company's corporate royalty bill. For the nine months ending September 30, 2010 $11.9 million in Alberta drilling credits have been recognized as a reduction to capital spending,
2. A one year flat 5% royalty period (18 months for horizontal wells) for each new well but capped at a cumulative production level of 500 MMcf for each new well, and
3. A Natural Gas Deep Drilling Holiday program that provides a holiday value for new wells based on meterage drilled. This holiday feature further reduces the royalty for new wells to a minimum of 5% for a maximum 5 year period from onstream date. This benefit sequentially follows the benefit under point (2) above.

From the combination of these royalty programs, Peyto has experienced a decrease in overall corporate royalty rates. This, in part, can be attributed to a decline in commodity prices and the dependence of royalty rates on commodity prices. In its 11 year history, Peyto has invested over $1.7 billion in capital projects and has found and developed gas reserves and has paid over $525 million in royalties.

Operating Costs & Transportation

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party production reduces operating expenses.

	Three Months ended September 30		Nine Months ended September 30	
	2010	2009	**2010**	2009
Operating costs ($000)				
Field expenses	**7,055**	6,839	**21,565**	20,962
Processing and gathering income	**(2,593)**	(2,857)	**(7,931)**	(8,223)
Total operating costs	**4,462**	3,982	**13,634**	12,739
$/mcfe	**0.34**	0.41	**0.37**	0.43
$/boe	**2.04**	2.43	**2.25**	2.56
Transportation	**1,785**	1,097	**4,798**	3,370
$/mcfe	**0.14**	0.11	**0.13**	0.11
$/boe	**0.82**	0.67	**0.79**	0.68

Operating costs were $4.5 million in the third quarter of 2010 compared to $4.0 for the same period in 2009. On a unit-of-production basis, operating costs averaged $0.34/mcfe in the third quarter of 2010 compared to $0.41/mcfe for the same period in 2009. This decline on a per unit basis is due to the increase in production volumes. Transportation expense increased on a per mcfe basis due to an increase in pipeline tariffs effective January 1, 2010.

General and Administrative Expenses

	Three Months ended September 30		Nine Months ended September 30	
	2010	2009	**2010**	2009
G&A expenses ($000)	**2,507**	2,343	**7,243**	7,351
Overhead recoveries	**(983)**	(825)	**(2,809)**	(1,691)
Net G&A expenses	**1,524**	1,518	**4,434**	5,660
$/mcfe	**0.12**	0.15	**0.12**	0.19
$/boe	**0.70**	0.93	**0.73**	1.14

General and administrative expenses before overhead recoveries were $2.5 million in the third quarter of 2010 consistent with $2.3 million during the same period a year earlier. Capital overhead recoveries increased 19 percent for the third quarter as a result of the increased capital program in 2010. General and administrative expenses averaged $0.12/mcfe in the third quarter of 2010 compared to $0.15/mcfe for the same period in 2009.

Interest Expense

	Three Months ended September 30		Nine Months ended September 30	
	2009	2009	**2009**	2009
Interest expense ($000)	**5,136**	4,493	**14,517**	11,919
$/mcfe	**0.39**	0.46	**0.40**	0.40
$/boe	**2.35**	2.74	**2.39**	2.39
Average interest rate	**4.8%**	4.3%	**4.6%**	3.3%

Third quarter 2010 interest expense was $5.1 million or $0.39/mcfe compared to $4.5 million or $0.46/mcfe for the same period in 2009 due to an increase in interest rates and higher average debt outstanding.

Netbacks

	Three Months ended September 30		Nine Months ended September 30	
($/mcfe)	**2009**	2009	**2009**	2009
Sale Price	**5.83**	6.20	**6.34**	6.73
Less: Royalties	**0.52**	0.46	**0.71**	0.61
Operating costs	**0.34**	0.41	**0.37**	0.43
Transportation	**0.14**	0.11	**0.13**	0.11
Field netback	**4.83**	5.22	**5.13**	5.58
General and administrative	**0.12**	0.15	**0.12**	0.19
Interest on long-term debt	**0.39**	0.46	**0.40**	0.40
Cash netback ($/mcfe)	**4.32**	4.61	**4.61**	4.99
Cash netback ($/boe)	**25.94**	27.65	**27.65**	29.97

Netbacks are a non-GAAP measure that represents the profit margin associated with the production and sale of petroleum and natural gas. Netbacks are per-unit of production measures used to assess the Trust's performance and efficiency. The primary factors that produce Peyto's strong netbacks and high margins are a low cost structure and the high heat content of its natural gas that results in higher commodity prices.

Depletion, Depreciation and Accretion

The 2010 third quarter provision for depletion, depreciation and accretion totaled $22.2 million compared to $18.0 million for the same period in 2009. On a unit-of-production basis, depletion, depreciation and accretion costs averaged $1.69/mcfe as compared to $1.83/mcfe a year earlier.

Income Taxes

The current recovery for future income tax is $1.0 million (2009 – recovery of $0.8 million). Peyto's trust structure is unique and was designed to provide for discretion at the operating trust level to distribute taxable income to the Trust. Resource pools are generated from the capital program, which are available to offset current and future income tax liabilities. Unitholders benefit as the Trust may use these resource pools to increase the tax free return of capital component of the cash distributions.

Recent amendments to the Income Tax Act (Canada) facilitate the conversion of existing income trusts into corporations. In general, the amendments permit alternative transactions which allow a conversion to be tax deferred for both the unitholders and the income trust. Peyto has now met with its advisors and determined that, barring any unforeseen legislative changes and pending unitholder and regulatory approval, the conversion of the Trust into a corporate form will occur effective December 31, 2010.

Canada Revenue Agency ("CRA") conducted an audit of Peyto Energy & Development Corp.'s ("Peyto") restructuring costs incurred in the 2003 trust conversion. On September 25, 2008, CRA reassessed on the basis that $41 million of these costs were not deductible and treated them as an eligible capital amount. Peyto filed a notice of objection and CRA confirmed the reassessment. On May 14, 2009, Peyto appealed to the Tax Court of Canada. Examinations for discovery of an officer of Peyto were completed in June 2010. Examinations of the CRA officer are on-going. If the matter cannot be settled, it is expected to go to trial.

MARKETING

Commodity Price Risk Management

The Trust is a party to certain off balance sheet derivative financial instruments, including fixed price contracts. The Trust enters into these forward contracts with well established counter-parties for the purpose of protecting a portion of its future revenues from the volatility of oil and natural gas prices. During the third quarter of 2010, a realized hedging gain of $12.9 million was recorded as compared to a hedging gain of $20.0 million for the same period in 2009. A summary of contracts outstanding in respect of the hedging activities are as follows:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
November 1 , 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.20/GJ
November 1 , 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.00/GJ
November 1, 2009 to March 31, 2011	Fixed Price	5,000 GJ	$6.20/GJ
November 1 , 2009 to March 31, 2011	Fixed price	5,000 GJ	$5.81/GJ
April 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$6.10/GJ
April 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$5.50/GJ
April 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$4.50/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.28/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.29/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.555/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.70/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$4.55/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$5.67/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$5.82/GJ
Ju.ly 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$4.03/GJ
Ju.ly 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$4.20/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$8.91/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$9.15/GJ
April 1 , 2011 to March 31, 2012	Fixed Price	5,000 GJ	$6.20/GJ
April 1 , 2011 to March 31, 2012	Fixed Price	5,000 GJ	$5.00/GJ
April 1 , 2011 to March 31, 2012	Fixed Price	5,000 GJ	$5.12/GJ
November 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.50/GJ

As at September 30, 2010, the Trust had committed to the future sale of 23,280,000 gigajoules (GJ) of natural gas at an average price of $5.07 per GJ or $5.93 per mcf. Had these contracts been closed on September 30, 2010, the Trust would have realized a gain in the amount of $41.5 million.

Subsequent to September 30, 2010 the Trust entered into the following contract:

Natural Gas Period Hedged	Type	Daily Volume	Price (CAD)
April 1 , 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.05/GJ

Commodity Price Sensitivity

Peyto’s earnings are largely determined by commodity prices for crude oil and natural gas including the US/Canadian dollar exchange rate. Volatility in these oil and gas prices can cause fluctuations in Peyto’s earnings over which the Trust has no control. Low operating costs and a long reserve life reduce Peyto’s sensitivity to changes in commodity prices.

Currency Risk Management

The Trust is exposed to fluctuations in the Canadian/US dollar exchange ratio since commodities are effectively priced in US dollars and converted to Canadian dollars. In the short term, this risk is mitigated indirectly as a result of a commodity hedging strategy that is conducted in a Canadian dollar currency. Over the long term, the Canadian dollar tends to rise as commodity prices rise. There is a similar correlation between oil and gas prices. Currently Peyto has not entered into any agreements to further manage its currency risks.

Interest Rate Risk Management

The Trust is exposed to interest rate risk in relation to interest expense on its revolving demand facility. Currently there are no agreements to manage this risk. At September 30, 2010, the increase or decrease in earnings for each 100 bps (1%) change in interest rate paid on the outstanding revolving demand loan amounts to approximately $1.1 million per quarter or $4.4 million per annum. Average debt outstanding for the third quarter of 2010 was $428.2 million.

LIQUIDITY AND CAPITAL RESOURCES

Funds from operations is reconciled to cash flows from operating activities below:

	Three Months ended September		Nine Months ended September 30	
($000)	**2010**	2009	**2010**	2009
Cash flows from operating activities	**48,681**	49,827	**156,986**	152,121
Change in non-cash working capital	**5,129**	(5,726)	**(704)**	(4,500)
Provision for performance based compensation	**2,933**	1,162	**11,435**	1,776
Funds from operations	**56,743**	45,263	**167,717**	149,397
Funds from operations per unit	**0.47**	0.39	**1.41**	1.37

For the third quarter ended September 30, 2010, funds from operations totaled $56.7 million or $0.47 per unit, as compared to $45.3 million, or $0.39 per unit for the same period in 2009. Peyto's policy is to balance distributions to unitholders and funding for a capital program with cash flow and available bank lines. Earnings and cash flow are highly sensitive to changes in commodity prices, exchange rates and other factors that are beyond Peyto's control. Current volatility in commodity prices creates uncertainty as to the funds from operations and capital expenditure budget. Accordingly, results are assessed throughout the year and operational plans revised as necessary to reflect the most current information.

Revenues will be impacted by drilling success and production volumes as well as external factors such as the market prices for commodities and the exchange rate of the Canadian dollar relative to the US dollar.

Bank Debt

The Trust has a syndicated $625 million extendible revolving credit facility with a stated term date of April 30, 2011. The facility is made up of a $20 million working capital sub-tranche and a $605 million production line. The facilities are available on a revolving basis for a period of at least 364 days and upon the term out date may be extended for a further 364 day period at the request of the Trust, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a one year term, at the end of which time the facility would be due and payable. The loan has therefore been classified as long-term on the balance sheet. The average borrowing rate for the three months ended September 30, 2010 was 4.8% (2009 – 4.3%). Outstanding amounts on this facility will bear interest at rates determined by the Trust's debt to cash flow ratio that range from prime plus 1.25% to prime plus 2.75% for debt to earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank.

At September 30, 2010, $455 million was drawn under the facility. Working capital liquidity is maintained by drawing from and repaying the unutilized credit facility as needed. At September 30, 2010, the working capital surplus was $21.0 million (including a non-cash current asset for an unrealized mark to market future hedging gain of $35.4 million).

Peyto believes funds generated from operations, together with borrowings under the credit facility will be sufficient to finance current operations and the planned capital expenditure program. The total amount of capital invested in 2010 will be driven by the number and quality of projects generated. Capital will only be invested if it meets the long term objectives of the Trust. The majority of the capital program will involve drilling, completion and tie-in of lower risk development gas wells. Peyto's rapidly scaleable business model has the flexibility to match planned capital expenditures to actual cash flow.

Net Debt

"Net debt" is a non-GAAP measure that is the sum of long-term debt and working capital excluding the current financial derivative instruments and current provision for future performance based compensation. It is used by management to analyze the financial position and leverage of the Trust. Net debt is reconciled below to long-term debt which is the most directly comparable GAAP measure:

($000)	**As at September 30, 2010**	As at December 31, 2009	As at September 30, 2009
Long-term debt	**455,000**	435,000	420,000
Current liabilities	**81,688**	71,681	56,314
Current assets	**(102,642)**	(73,503)	(65,327)
Financial derivative instruments	**35,399**	8,683	13,954
Provision for future performance based compensation	**(11,486)**	(2,001)	(976)
Net debt	**457,959**	439,860	423,965

Capital

Authorized: Unlimited number of voting trust units

Issued and Outstanding

Trust Units (no par value) ($000)	**Number of Units**	**Amount**
Balance, December 31, 2008	**105,920,194**	**410,233**
Trust units issued	9,000,000	94,500
Trust units issuance costs (net of tax)	-	(4,326)
Balance, December 31, 2009	**114,920,194**	**500,407**
Trust units issued by private placement	196,420	2,728
Trust units issued	5,566,000	74,863
Trust units issuance costs (net of tax)	-	(3,163)
Trust units issued pursuant to DRIP	461,516	6,250
Trust units issued pursuant to OTUPP	992,548	13,352
Balance, September 30, 2010	**122,136,678**	**594,437**

On June 26, 2009, Peyto closed an offering of 9,000,000 trust units at a price of $10.50 per trust unit, receiving net proceeds of $90.2 million (net of issuance costs).

On December 31, 2009 the Trust completed a private placement of 196,420 trust units to employees and consultants for net proceeds of $2.7 million ($13.89 per unit). These trust units were issued on January 6, 2010.

On April 27, 2010, Peyto closed an offering of 5,566,000 trust units at a price of $13.45 per trust unit, receiving net proceeds of $71.7 million (net of issuance costs).

Peyto reinstated its amended distribution reinvestment and optional trust unit purchase plan (the "Amended DRIP Plan") effective with the January 2010 distribution whereby eligible unitholders may elect to reinvest their monthly cash distributions in additional trust units at a 5 percent discount to market price. The DRIP plan incorporates an Optional Trust Unit Purchase Plan ("OTUPP") which provides unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP.

Subsequent to September 30, 2010, 444,558 trust units (64,677 pursuant to the DRIP and 379,881 pursuant to the OTUPP) were issued for net proceeds of $6.1 million. Subsequent to the issuance of these units, 122,581,236 trust units were outstanding.

Performance Based Compensation

The Trust awards performance based compensation to employees and key consultants annually. The performance based compensation is comprised of market and reserve value based components.

The reserve value based component is 4% of the incremental increase in value, if any, as adjusted to reflect changes in debt, equity and distributions, of proved producing reserves calculated using a constant price at December 31 of the current year and a discount rate of 8%. This methodology can generate interim results which vary significantly from the final compensation paid No provision for compensation expense was recorded for the third quarter of 2010. The cumulative provision totals $3.0 million.

Under the market based component, rights vest which over a three year vesting period are allocated to employees and key consultants. The number of rights outstanding at any time is not to exceed 6% of the total number of trust units outstanding. At December 31 of each year, all vested rights are automatically cancelled and, if applicable, paid out in cash. Compensation is calculated as the number of vested rights multiplied by the total of the market appreciation (market price over the price at the date of grant and associated distributions).

Based on the weighted average trading price of the trust units for the period ended September 30, 2010, compensation costs related to 4.5 million non-vested rights (4% of the total number of trust units outstanding), with an average grant price of $13.50, are $2.8 million. The Trust records a non-cash provision for future compensation expense over the life of the rights. The cumulative provision totals $11.4 million.

Capital Expenditures

Net capital expenditures for the third quarter of 2010 totaled $64.1 million. Exploration and development related activity net of drilling royalty credits represented $45.2 million (70% of total), while expenditures on facilities, gathering systems and equipment totaled $14.1 million (22% of total) and land, seismic and acquisitions totaled $4.8 million (8% of total). The following table summarizes capital expenditures for the quarter.

	Three Months ended September 30		Nine Months ended September 30	
($000)	**2010**	2009	**2010**	2009
Land	**4,104**	957	**4,348**	1,065
Seismic	**23**	649	**132**	826
Drilling – Exploratory & Development	**47,210**	25,807	**123,109**	39,476
Production Equipment, Facilities & Pipelines	**14,076**	2,672	**34,334**	6,425
Acquisitions	**700**	1,900	**903**	1,900
Drilling Royalty Credit	**(1,990)**	(3,400)	**(11,903)**	(3,400)
Office Equipment	**-**	140	**-**	140
Total Capital Expenditures	**64,123**	28,725	**150,923**	46,432

Distributions

	Three Months ended September 30		Nine Months ended September 30	
	2010	2009	**2010**	2009
Funds from operations ($000)	**56,743**	45,263	**167,717**	149,397
Total distributions ($000)	**43,875**	41,371	**128,969**	121,891
Total distributions per unit ($)	**0.36**	0.36	**1.08**	1.12
Payout ratio (%)	**77**	91	**77**	82
Total cash distributions (net of DRIP) ($000)	**40,609**	41,371	**121,836**	121,891
Payout ratio (net of DRIP) (%)	**72**	91	**73**	82

Peyto’s policy is to balance distributions to unitholders and funding for a capital program with cash flow and available bank lines. The Board of Directors is prepared to adjust the payout ratio levels (distributions declared divided by funds from operations) to achieve the desired distributions while maintaining an appropriate capital structure. For Canadian income tax purposes distributions made are considered a combination of income and return of capital. The portion that is return of capital reduces the adjusted cost base of the units.

Sustainability of Distributions

($000)	**Three months ended September 30, 2010**	**Nine months ended September 30, 2010**	Year ended December 31, 2009
Cash flows from operating activities	**48,681**	**156,986**	198,688
Earnings for the period	**32,567**	**94,138**	152,774
Distribution declared	**(43,875)**	**(128,968)**	(163,263)
Excess of cash flows from operating activities over distributions declared	**4,806**	**28,018**	35,425
(Shortfall) excess of earnings over distributions declared	**(11,308)**	**(34,830)**	(10,489)

Shortfalls of earnings over distributions paid are a result of non-cash charges such as depletion, depreciation and accretion and future income taxes which also have no immediate impact on distribution sustainability.

Accumulated Earnings and Distributions

	Three Months ended September 30		Nine Months ended September 30	
($000)	**2010**	2009	**2010**	2009
Opening accumulated earnings (before distributions)	**1,133,780**	1,012,197	**1,072,209**	919,435
Earnings for the period	**32,567**	26,976	**94,138**	119,738
Total accumulated earnings (before distributions)	**1,166,347**	1,039,173	**1,166,347**	1,039,173
Total accumulated distributions	**(1,101,428)**	(931,088)	**(1,101,428)**	(931,088)
Accumulated earnings (after distributions) per Balance Sheet	**64.919**	108,085	**64,919**	108,085

Since inception, Peyto has accumulated earnings of $1.2 billion and distributed $1.1 billion to unitholders.

Contractual Obligations

The Trust is committed to payments under operating leases for office space as follows:

($000)	**September 30, 2010**
2010	260
2011	1,043
2012	1,043
2013	1,043
2014	1,043
	4,432

RELATED PARTY TRANSACTIONS

An officer and director of the Trust is a partner of a law firm that provides legal services to the Trust. The fees charged are based on standard rates and time spent on matters pertaining to the Trust and its subsidiaries.

INCOME TAXES

The following sets out a general discussion of the Canadian and US tax consequences of holding Peyto units as capital property. The summary is not exhaustive in nature and is not intended to provide legal or tax advice. Unitholders or potential Unitholders should consult their own legal or tax advisors as to their particular tax consequences.

Canadian Taxpayers
The Trust qualifies as a mutual fund trust under the *Income Tax Act* (Canada) and, accordingly, Trust units are qualified investments for RRSPs, RRIFs, RESPs, TFSAs and DPSPs. Each year, the Trust is required to file an income tax return and any taxable income of the Trust is allocated to unitholders.

Unitholders are required to include in computing income their pro-rata share of any taxable income earned by the Trust in that year. An investor's adjusted cost base (ACB) in a trust unit equals the purchase price of the unit less any non-taxable cash distributions received from the date of acquisition. To the extent the unitholders' ACB is reduced below zero, such amount will be deemed to be a capital gain to the unitholder and the unitholders' ACB will be brought to nil.

During the third quarter of 2010, the Trust paid distributions to the unitholders in the amount of $43.9 million (2009 - $41.4 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit [1]
January 2010	January 31, 2010	February 15, 2010	$0.12
February 2010	February 28, 2010	March 15, 2010	$0.12
March 2010	March 31, 2010	April 15, 2010	$0.12
April 2010	April 30, 2010	May 14, 2010	$0.12
May 2010	May 31, 2010	June 15, 2010	$0.12
June 2010	June 30, 2010	July 15, 2010	$0.12
July 2010	July 31, 2010	August 13, 2010	$0.12
August 2010	August 31, 2010	September 15, 2010	$0.12
September 2010	September 30, 2010	October 15, 2010	$0.12

[1] Distributions per trust unit reflect the sum of the per trust unit amounts declared monthly to unitholders.

US Taxpayers
US unitholders who receive cash distributions are subject to a 15% Canadian withholding tax. US taxpayers may be eligible for a foreign tax credit with respect to Canadian withholding taxes paid.

The taxable portion of the cash distributions, if any, is determined by the Trust in relation to its current and accumulated earnings and profit using US tax principles. The taxable portion so determined, is considered to be a dividend for US tax purposes.

The non-taxable portion of the cash distributions is a return of the cost (or other basis). The cost (or other basis) is reduced by this amount for computing any gain or loss from disposition. However, if the full amount of the cost (or other basis) has been recovered, any further non-taxable distributions should be reported as a gain.

US unitholders are advised to seek legal or tax advice from their professional advisors.

RISK MANAGEMENT

Investors who purchase units are participating in the net funds from operations from a portfolio of western Canadian crude oil and natural gas producing properties. As such, the funds from operations paid to investors and the value of the units are subject to numerous risks inherent in the oil and natural gas industry.

Expected funds from operations depends largely on the volume of petroleum and natural gas production and the price received for such production, along with the associated costs. The price received for oil depends on a number of factors, including West Texas Intermediate oil prices, Canadian/US currency exchange rates, quality differentials and Edmonton par oil prices. The price received for natural gas production is primarily dependent on current Alberta market prices. Peyto's marketing strategy is designed to smooth out short term fluctuations in the price of natural gas through future sales. It is meant to be methodical and consistent and to avoid speculation.

Although Peyto's focus is on internally generated drilling programs, any acquisition of oil and natural gas assets depends on an assessment of value at the time of acquisition. Incorrect assessments of value can adversely affect distributions to unitholders and the value of the units. Peyto employs experienced staff and performs appropriate levels of due diligence on the analysis of acquisition targets, including a detailed examination of reserve reports; if appropriate, re-engineering of reserves for a large portion of the properties to ensure the results are consistent; site examinations of facilities for environmental liabilities; detailed examination of balance sheet accounts; review of contracts; review of prior year tax returns and modeling of the acquisition to attempt to ensure accretive results to the unitholders.

Inherent in development of the existing oil and gas reserves are the risks, among others, of drilling dry holes, encountering production or drilling difficulties or experiencing high decline rates in producing wells. To minimize these risks, Peyto employs experienced staff to evaluate and operate wells and utilize appropriate technology in operations. In addition, prudent work practices and procedures, safety programs and risk management principles, including insurance coverage protect the Trust against certain potential losses.

The value of Peyto’s units is based on among other things, the underlying value of the oil and natural gas reserves. Geological and operational risks can affect the quantity and quality of reserves and the cost of ultimately recovering those reserves. Lower oil and gas prices increase the risk of write-downs on oil and gas property investments. In order to mitigate this risk, proven and probable oil and gas reserves are evaluated each year by a firm of independent reservoir engineers. The reserves committee of the Board of Directors reviews and approves the reserve report.

Access to markets may be restricted at times by pipeline or processing capacity. These risks are minimized by controlling as much of the processing and transportation activities as possible and ensuring transportation and processing contracts are in place with reliable cost efficient counter-parties.

The petroleum and natural gas industry is subject to extensive controls, regulatory policies and income and resource taxes imposed by various levels of government. These regulations, controls and taxation policies are amended from time to time. Peyto has no control over the level of government intervention or taxation in the petroleum and natural gas industry. The Trust operates in such a manner to ensure, to the best of its knowledge that it is in compliance with all applicable regulations and are able to respond to changes as they occur.

The petroleum and natural gas industry is subject to both environmental regulations and an increased environmental awareness. Peyto has reviewed its environmental risks and is, to the best of its knowledge, in compliance with the appropriate environmental legislation and have determined that there is no current material impact on operations.

Peyto is subject to financial market risk. In order to maintain substantial rates of growth, the Trust must continue reinvesting in, drilling for or acquiring petroleum and natural gas. The capital expenditure program is funded primarily through funds from operations, debt and, if appropriate, equity.

CONTROLS AND PROCEDURES

Disclosure Controls and Procedures

The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, disclosure controls and procedures to provide reasonable assurance that: (i) material information relating to the Trust is made known to the Trust's Chief Executive Officer and Chief Financial Officer by others, particularly during the period in which the annual and interim filings are being prepared; and (ii) information required to be disclosed by the Trust in its annual filings, interim filings or other reports filed or submitted by it under securities legislation is recorded, processed, summarized and reported within the time period specified in securities legislation. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Trust's disclosure controls and procedures at the interim period end of the Trust and have concluded that the Trust's disclosure controls and procedures are effective at the financial period end of the Trust for the foregoing purposes.

Internal Control over Financial Reporting

The Trust's Chief Executive Officer and Chief Financial Officer have designed, or caused to be designed under their supervision, internal control over financial reporting to provide reasonable assurance regarding the reliability of the Trust's financial reporting and the preparation of financial statements for external purposes in accordance with the Canadian GAAP. Such officers have evaluated, or caused to be evaluated under their supervision, the effectiveness of the Trust's internal control over financial reporting at the financial period end of the Trust and concluded that the Trust's internal control over financial reporting is effective, at the financial period end of the Trust, for the foregoing purpose.

The Trust is required to disclose herein any change in the Trust's internal control over financial reporting that occurred during the period ended September 30, 2010 that has materially affected, or is reasonably likely to materially affect, the Trust's internal control over financial reporting. No material changes in the Trust's internal control over financial reporting were identified during such period that has materially affected, or are reasonably likely to materially affect, the Trust's internal control over financial reporting.

It should be noted that a control system, including the Trust's disclosure and internal controls and procedures, no matter how well conceived, can provide only reasonable, but not absolute, assurance that the objectives of the control system will be met and it should not be expected that the disclosure and internal controls and procedures will prevent all errors or fraud.

CRITICAL ACCOUNTING ESTIMATES

Reserve Estimates

Estimates of oil and natural gas reserves, by necessity, are projections based on geologic and engineering data, and there are uncertainties inherent to the interpretation of such data as well as the projection of future rates of production and the timing of development expenditures. Reserve engineering is an analytical process of estimating underground accumulations of oil and natural gas that can be difficult to measure. The accuracy of any reserve estimate is a function of the quality of available data, engineering and geological interpretation and judgment. Estimates of economically recoverable oil and natural gas reserves and future net cash flows necessarily depend upon a number of variable factors and assumptions, such as historical production from the area compared with production from other producing areas, the assumed effects of regulations by governmental agencies and assumptions governing future oil and natural gas prices, future royalties and operating costs, development costs and workover and remedial costs, all of which may in fact vary considerably from actual results. For these reasons, estimates of the economically recoverable quantities of oil and natural gas attributable to any particular group of properties, classifications of such reserves based on risk recovery, and estimates of the future net cash flows expected there from may vary substantially. Any significant variance in the assumptions could materially affect the estimated quantity and value of the reserves, which could affect the carrying value of the Trust's oil and natural gas properties and the rate of depletion of the oil and natural gas properties as well as the calculation of the reserve value based compensation. Actual production, revenues and expenditures with respect to the Trust's reserves will likely vary from estimates, and such variances may be material.

The Trust's estimated quantities of proved and probable reserves at December 31, 2009 were audited by independent petroleum engineers Paddock Lindstrom & Associates Ltd. Paddock has been evaluating reserves in this area and for Peyto for 11 consecutive years.

Depletion and Depreciation Estimate

The full cost method of accounting for petroleum and natural gas operations is followed whereby all costs of exploring for and developing petroleum and natural gas reserves are capitalized. Such costs include land acquisition costs, geological and geophysical costs, carrying charges on non-producing properties, costs of drilling both productive and non-productive wells and overhead charges directly related to acquisition, exploration and development activities.

All costs of exploring for and developing petroleum and natural gas reserves, together with the costs of production equipment, are depleted and depreciated on the unit-of-production method based on estimated gross proven reserves. Petroleum and natural gas reserves and production are converted into equivalent units based upon estimated relative energy content (6 mcf to 1 barrel of oil).

Costs of acquiring unproved properties are initially excluded from depletion calculations. These unevaluated properties are assessed periodically to ascertain whether impairment has occurred. When proven reserves are assigned or the property is considered to be impaired, the cost of the property or the amount of the impairment is added to costs subject to depletion calculations.

Full Cost Accounting Ceiling Test

The carrying value of property, plant and equipment is reviewed at least annually for impairment. Impairment occurs when the carrying value of the assets is not recoverable by the future undiscounted cash flows. The ceiling test is based on estimates of proved reserves, production rates, estimated future petroleum and natural gas prices and costs and other relevant assumptions. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material. Any impairment would be charged as additional depletion and depreciation expense.

Asset Retirement Obligation

The asset retirement obligation is estimated based on existing laws, contracts or other policies. The fair value of the obligation is based on estimated future costs for abandonment and reclamation discounted at a credit adjusted risk free rate. The liability is adjusted each reporting period to reflect the passage of time and for revisions to the estimated future cash flows, with the accretion charged to earnings. By their nature, these estimates are subject to measurement uncertainty and the impact on the financial statements could be material.

Future Market Performance Based Compensation

The provision for future market based compensation is estimated based on current market conditions, distribution history and on the assumption that all outstanding rights will be paid out according to the vesting schedule. The conditions at the time of vesting could vary significantly from the current conditions and may have a material effect on the calculation.

Reserve Value Performance Based Compensation

The reserve value based compensation is calculated using the year end independent reserves evaluation which was completed in January 2010. A quarterly provision for the reserve value based compensation is calculated using estimated proved producing reserve additions adjusted for changes in debt, equity and distributions. Actual proved producing reserves additions and forecasted commodity prices could vary significantly from those estimated and may have a material effect on the calculation.

Income Taxes

The determination of the Trust's income and other tax liabilities requires interpretation of complex laws and regulations often involving multiple jurisdictions. All tax filings are subject to audit and potential reassessment after the lapse of considerable time. Accordingly, the actual income tax liability may differ significantly from that estimated and recorded.

Accounting Changes

Voluntary changes in accounting policy are made only if they result in financial statements which provide more reliable and relevant information. Accounting policy changes are applied retrospectively unless it is impractical to determine the period or cumulative impact of the change. Corrections of prior period errors are applied retrospectively and changes in accounting estimates are applied prospectively by including these changes in earnings. When the Trust has not applied a new primary source of GAAP that has been issued, but is not effective, the Trust will disclose the fact along with information relevant to assessing the possible impact that application of the new primary source of GAAP will have on the financial statements in the period of initial application.

CHANGES IN ACCOUNTING POLICIES

International Financial Reporting Standards

The Accounting Standards Board (AcSB) confirmed in February 2008 that International Financial Reporting Standards (IFRS) will replace Canadian GAAP for publicly accountable enterprises for financial periods beginning on or after January 1, 2011. Accordingly, the conversion from Canadian GAAP to IFRS will be applicable to the Trust's reporting for the first quarter of 2011 for which current and comparative information will be prepared under IFRS.

Peyto's project consists of three key phases:

- Scoping and diagnostic phase – this phase involves performing a high level impact analysis to identify areas that may be affected by the transition to IFRS. The results of this analysis are priority ranked according to complexity and the amount of time required assessing the impact of changes in transitioning to IFRS.

- Impact analysis and evaluation phase – during this phase, items identified in the diagnostic phase are addressed according to the priority levels assigned to them. This phase involves analysis of policy choices allowed under IFRS and their impact on the financial statements. In addition, certain potential differences are further investigated to assess whether there may be a broader impact to Peyto's debt agreements, compensation arrangements or management reporting systems. The conclusion of the impact analysis and evaluation phase will require the audit committee of the Board of Directors to review all accounting policy choices as proposed by management.

- Financial implementation phase – involves implementation of all changes approved in the impact analysis phase and will include changes to information systems, business processes, modification of agreements and training of all staff who are impacted by the conversion.

Peyto has completed the scoping and diagnostic phase and has prepared draft analysis for the impact analysis and evaluation phase. Management has not yet finalized its accounting policies and as such is unable to quantify the impact of adopting IFRS on the financial statements. In addition, due to anticipated changes to IFRS and International Accounting Standards prior to the Trust's adoption of IFRS, management's plan is subject to change based on new facts and circumstances that arise after the date of this MD&A.

The transition from Canadian GAAP to IFRS is a significant undertaking that may materially affect the Trust's reported financial position and results of operations. At this time, Peyto has identified key differences that will impact the financial statements as follows:

- Re-classification of Exploration and Evaluation ("E&E") expenditures from PP&E – Upon transition to IFRS, Peyto will reclassify any E&E expenditures that are currently included in PP&E on the Consolidated Balance Sheet. E&E assets will not be depleted and must be assessed for impairment when indicators suggest the possibility of impairment. Peyto does not expect to have a significant E&E balance.

- Calculation of depletion expense for PP&E assets – Upon transition to IFRS, Peyto has the option to calculate depletion using a reserve base of proved reserves or both proved and probable reserves, as compared to the Canadian GAAP method of calculating depletion using only proved reserves. Peyto will calculate depletion using a proved reserve basis.

- Impairment of PP&E assets – Under IFRS, impairment of PP&E must be calculated at a more granular level than what is currently required under Canadian GAAP. Impairment calculations were performed at the cash generating unit level using either total proved plus probable reserves. Impairment testing has been completed and no significant impacts were identified.

- Provisions for asset retirement costs – Under IFRS, Peyto is required to revalue its entire liability for asset retirement costs at each balance sheet date using a current liability-specific discount rate. Under Canadian GAAP, once recorded, asset retirement obligations are not adjusted for future changes in discount rates.

- Provision for future market based compensation - the Trust issues stock-based compensation awards which are valued at intrinsic value under Canadian GAAP. Upon the adoption of IFRS, this liability will be restated to fair value.

First Time Adoption of IFRS

IFRS 1 provides entities adopting IFRS for the first time with a number of optional exemptions and mandatory exceptions in certain areas to the general requirement for full retrospective application of IFRS. Management is analyzing the various accounting policy choices available and will implement those determined to be the most appropriate for the Trust which are summarized as follows:

- Property Plant and Equipment ("PP&E") – IFRS 1 provides the option to retrospectively restate PP&E assets at their deemed cost being the Canadian GAAP net book value assigned to these assets as at the date of transition, January 1, 2010 rather than restating historical cost. The Trust will apply this exemption.

- Asset Retirement Obligation ("ARO) – As the PP&E IFRS 1 exemption will be taken any change in the liability for ARO will be charged to Retained Earnings.

In addition to accounting policy differences, Peyto's transition to IFRS is expected to impact its internal controls over financial reporting, disclosure controls and procedures, information systems and certain of the Trust's business activities as follows:

Internal controls over financial reporting ("ICFR") – After the review of Peyto's accounting policies is complete, an assessment will be made to determine changes required for ICFR. As an example, additional controls may be implemented for the IFRS 1 changes such as the potential allocation of Peyto's PP&E as well as the process for reclassifying Peyto's E&E expenditures from PP&E. This will be an ongoing process throughout 2010 to ensure that all changes in accounting policies include the appropriate additional controls and procedures for future IFRS reporting requirements.

Disclosure controls and procedures – Throughout the transition process, Peyto will be assessing its stakeholders' information requirements and will ensure that adequate and timely information is provided to meet these needs.

Information systems – Peyto is assessing its systems capabilities and identifying any changes required to support Canadian GAAP and IFRS reporting. Modifications are being made to track PP&E and E&E expenditures at the level required by IFRS. Additional modifications may be required as we finalize our accounting policy choices.

Business activities – Management has been cognizant of the upcoming transition to IFRS and as such has worked with its counterparties and lenders to ensure that any agreements that contain references to Canadian GAAP financial statements are modified to allow for IFRS statements. Based on the expected changes to Peyto's accounting policies at this time, no issues are expected with the existing wording of debt covenants and related agreements as a result of the conversion to IFRS. Management will continue to monitor these areas closely as final policy choices are made.

ADDITIONAL INFORMATION

Additional information relating to Peyto Energy Trust can be found on SEDAR at www.sedar.com and www.peyto.com.

Quarterly information

	2010			2009	
	Q3	Q2	Q1	Q4	Q3
Operations					
Production					
Natural gas (mcf/d)	**122,717**	112,422	103,934	95,467	89,259
Oil & NGLs (bbl/d)	**3,322**	3,465	3,330	3,222	2,916
Barrels of oil equivalent (boe/d @ 6:1)	**23,775**	22,202	20,653	19,133	17,792
Thousand cubic feet equivalent (mcfe/d @ 6:1)	**142,651**	133,211	123,916	114,798	106,755
Average product prices					
Natural gas ($/mcf)	**5.16**	5.25	6.34	6.17	5.74
Oil & natural gas liquids ($/bbl)	**59.66**	65.58	68.93	60.77	51.06
$/MCFE					
Average sale price ($/mcfe)	**5.83**	6.14	7.17	6.84	6.20
Average royalties paid ($/mcfe)	**0.52**	0.81	0.82	0.71	0.46
Average operating expenses ($/mcfe)	**0.34**	0.38	0.41	0.38	0.41
Average transportation costs ($/mcfe)	**0.14**	0.13	0.13	0.11	0.11
Field netback ($/mcfe)	**4.83**	4.82	5.81	5.64	5.22
General & administrative expense ($/mcfe)	**0.12**	0.09	0.16	0.15	0.15
Interest expense ($/mcfe)	**0.39**	0.41	0.40	0.44	0.46
Cash netback ($/mcfe)	**4.32**	4.32	5.25	5.05	4.61
Financial ($000 except per unit)					
Revenue	**76,450**	74,370	79,974	72,218	60,860
Royalties	**6,800**	9,721	9,173	7,457	4,507
Funds from operations	**56,743**	52,415	58,559	53,302	45,263
Funds from operations per unit	**0.47**	0.44	0.51	0.46	0.39
Total distributions	**43,875**	43,622	41,470	41,371	41,371
Total distributions per unit	**0.36**	0.36	0.36	0.36	0.36
Payout ratio	**77%**	83%	71%	78%	91%
Earnings	**32,567**	24,696	36,874	33,035	26,976
Earnings per diluted unit	**0.27**	0.21	0.32	0.28	0.24
Capital expenditures	**64,123**	37,439	49,361	26,307	28,725
Weighted average trust units outstanding	**121,765,712**	119,419,799	115,153,667	114,920,194	114,920,194

Peyto Energy Trust

Consolidated Balance Sheets
($000)
(unaudited)

	September 30, 2010	December 31, 2009
Assets		
Current		
Cash	**6,628**	-
Accounts receivable *(Note 3 and 10)*	**56,249**	58,305
Due from private placement *(Note 6)*	**-**	2,728
Financial derivative instruments *(Note 10)*	**35,399**	8,683
Prepaid expenses and deposits	**4,366**	3,787
	102,642	73,503
Financial derivative instruments *(Note 10)*	**6,115**	1,253
Prepaid capital	**3,362**	955
Property, plant and equipment *(Note 4)*	**1,265,816**	1,178,402
	1,275,293	1,180,610
	1,377,935	1,254,113
Liabilities and Unitholders' Equity		
Current		
Accounts payable and accrued liabilities	**55,546**	55,890
Distributions payable	**14,656**	13,790
Provision for future performance based compensation	**11,486**	2,001
	81,688	71,681
Long-term debt *(Note 5)*	**455,000**	435,000
Provision for future performance based compensation	**2,990**	1,041
Asset retirement obligations	**11,449**	10,487
Future income taxes	**127,232**	123,421
	596,671	569,949
Unitholders' equity		
Unitholders' capital *(Note 6)*	**594,437**	500,407
Units to be issued *(Note 6)*	**6,064**	2,728
	600,501	503,135
Accumulated earnings *(Note 7)*	**64,919**	99,749
Accumulated other comprehensive income	**34,156**	9,599
	99,075	109,348
	699,576	612,483
	1,377,935	1,254,113

See accompanying notes

On behalf of the Board:

(signed) *"Michael MacBean"*
Director

(signed) *"Darren Gee"*
Director

Peyto Energy Trust

Consolidated Statements of Earnings
($000 except per unit amounts)
(unaudited)

	Three Months Ended Sept 30		Nine Months Ended Sept 30	
	2010	**2009**	**2010**	**2009**
Revenue				
Oil and gas sales	**63,578**	40,841	**200,669**	150,390
Realized gain on hedges	**12,872**	20,019	**30,124**	50,909
Royalties	**(6,800)**	(4,507)	**(25,693)**	(18,214)
Petroleum and natural gas sales, net	**69,650**	56,353	**205,100**	183,085
Expenses				
Operating *(Note 8)*	**4,462**	3,982	**13,634**	12,739
Transportation	**1,785**	1,097	**4,798**	3,370
General and administrative*(Note 9)*	**1,524**	1,518	**4,434**	5,660
Future performance based compensation provision	**2,933**	1,162	**11,435**	1,776
Interest on long term debt	**5,136**	4,493	**14,517**	11,919
Depletion, depreciation and accretion *(Note 4)*	**22,230**	17,966	**64,549**	54,261
	38,070	30,218	**113,367**	89,725
Earnings before taxes	**31,580**	26,135	**91,733**	93,360
Taxes				
Future income tax recovery	**987**	841	**2,405**	26,378
Earnings for the period	**32,567**	26,976	**94,138**	119,738
Earnings per unit *(Note 6)*				
Basic and diluted	**0.27**	0.24	**0.79**	1.10

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Comprehensive Income
($000 except per unit amounts)
(unaudited)

	Three Months Ended Sept 30		Nine Months Ended Sept 30	
	2010	**2009**	**2010**	**2009**
Earnings for the period	**32,567**	26,976	**94,138**	119,738
Other comprehensive income				
Change in unrealized gain (loss) on cash flow hedges	**18,104**	(2,497)	**54,681**	37,025
Realized (gain) loss on cash flow hedges	**(12,872)**	(20,019)	**(30,124)**	(50,909)
Comprehensive income	**37,799**	4,460	**118,695**	105,854

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Accumulated Earnings and Accumulated Other Comprehensive Income
($000)
(unaudited)

	Three Months Ended Sept 30		**Nine Months Ended Sept 30**	
	2010	**2009**	**2010**	**2009**
Accumulated earnings, beginning of period	**76,227**	122,480	**99,749**	110,238
Net earnings for the period	**32,567**	26,976	**94,138**	119,738
Distributions *(Note 7)*	**(43,875)**	(41,371)	**(128,968)**	(121,891)
Accumulated earnings, end of period	**64,919**	108,085	**64,919**	108,085
Accumulated other comprehensive income, beginning of period	**28,924**	38,878	**9,599**	30,246
Other comprehensive income (loss)	**5,232**	(22,516)	**24,557**	(13,884)
Accumulated other comprehensive income, end of period	**34,156**	16,362	**34,156**	16,362

See accompanying notes

Peyto Energy Trust

Consolidated Statements of Cash Flows
($000)
(unaudited)

	Three Months Ended Sept 30		Nine Months Ended Sept 30	
	2010	**2009**	**2010**	**2009**
Cash provided by (used in)				
Operating Activities				
Earnings for the period	**32,567**	26,976	**94,138**	119,738
Items not requiring cash:				
Future income tax recovery	**(987)**	(841)	**(2,405)**	(26,378)
Depletion, depreciation and accretion	**22,230**	17,966	**64,549**	54,261
Change in non-cash working capital related to operating activities	**(5,129)**	5,726	**704**	4,500
	48,681	49,827	**156,986**	152,121
Financing Activities				
Issuance of trust units *(Note 6)*	**11,245**	-	**93,396**	94,500
Issuance costs *(Note 6)*	**-**	(17)	**(3,968)**	(5,106)
Cash distribution paid (net of DRIP)	**(40,609)**	(41,371)	**(121,836)**	(121,891)
Increase (decrease) in bank debt	**25,000**	(40,000)	**20,000**	(80,000)
Change in non-cash working capital related to financing activities	**771**	-	**3,594**	(2,097)
	(3,593)	(81,388)	**(8,814)**	(114,594)
Investing Activities				
Additions to property, plant and equipment	**(67,485)**	(28,725)	**(153,409)**	(46,432)
Change in non-cash working capital related to investing activities	**19,750**	18,722	**11,865**	8,905
	(47,735)	(10,003)	**(141,544)**	(37,527)
Net increase (decrease) in cash	**(2,647)**	(41,564)	**6,628**	-
Cash, beginning of period	**9,275**	41,564	**-**	-
Cash, end of period	**6,628**	-	**6,628**	-

See accompanying notes

Peyto Energy Trust

Notes to Consolidated Financial Statements
(unaudited)

September 30, 2010 and 2009

1. Summary of Significant Accounting Policies

The unaudited interim consolidated financial statements of Peyto Energy Trust (the "Trust" or "Peyto") follow the same accounting policies as the most recent annual audited consolidated financial statements. The interim consolidated financial statement note disclosures do not include all of those required by Canadian generally accepted accounting principles ("GAAP") applicable for annual financial statements. Accordingly, these interim financial statements should be read in conjunction with the 2009 audited consolidated financial statements.

These financial statements include the accounts of Peyto Energy Trust and its wholly owned subsidiaries, Peyto Exploration & Development Corp., Peyto Operating Trust, Peyto Energy Limited Partnership and Peyto Energy Administration Corp.

2. Changes in Accounting Policies

Pending Accounting Pronouncements

In January 2006, the CICA Accounting Standards Board ("ASCB") adopted a strategic plan for the direction of accounting standards in Canada. As part of that plan, accounting standards in Canada for public companies are expected to converge with International Financial Reporting Standards ("IFRS") by 2011.

3. Accounts Receivable

($000)	**September 30, 2010**	December 31, 2009
Accounts receivable – general	**49,094**	51,150
Accounts receivable – income taxes	**7,155**	7,155
	56,249	58,305

Canada Revenue Agency ("CRA") has conducted an audit of restructuring costs claimed as a result of the Trust conversion in 2003 that has resulted in the reclassification of $41.0 million dollars in employment related costs as eligible capital. In October, 2008, the Trust received a notice of reassessment from the CRA and paid an amount of $7.2 million related to this audit. Based upon consultation with legal counsel, Management's view is that CRA's position has no merit. A notice of appeal was filed May 19, 2009 and the appeal has been denied. Examinations of the CRA officer are on-going. If the matter cannot be settled, it is expected to go to trial.

4. Property, Plant and Equipment

($000)	**September 30, 2010**	December 31, 2009
Property, plant and equipment	**1,776,070**	1,624,655
Accumulated depletion and depreciation	**(510,254)**	(446,253)
	1,265,816	1,178,402

At September 30, 2010 costs of $29.6 million (December 31, 2009 - $26.6 million) related to undeveloped land have been excluded from the depletion and depreciation calculation.

5. Long-Term Debt

The Trust has a syndicated $625 million extendible revolving credit facility with a stated term date of April 30, 2011. The facility is made up of a $20 million working capital sub-tranche and a $605 million production line. The facilities are available on a revolving basis for a period of at least 364 days and upon the term out date may be extended for a further 364 day period at the request of the Trust, subject to approval by the lenders. In the event that the revolving period is not extended, the facility is available on a non-revolving basis for a further one year term, at the end of which time the facility would be due and payable. Outstanding amounts on this facility bear interest at rates determined by the Trust's debt to cash flow ratio that range from prime to prime plus 1.25% to 2.75% for debt to earnings before interest, taxes, depreciation, depletion and amortization (EBITDA) ratios ranging from less than 1:1 to greater than 2.5:1. A General Security Agreement with a floating charge on land registered in Alberta is held as collateral by the bank. The average borrowing rate for the three and nine months ended September 30, 2010 was 4.8% and 4.6% respectively (2009 – 3.1% and 3.0% respectively).

6. Unitholders' Capital

Authorized: Unlimited number of voting trust units

Issued and Outstanding

Trust Units (no par value) ($000)	Number of Units	Amount
Balance, December 31, 2008	**105,920,194**	**410,233**
Trust units issued	9,000,000	94,500
Trust unit issuance costs (net of tax)	-	(4,326)
Balance, December 31, 2009	**114,920,194**	**500,407**
Trust units issued by private placement	196,420	2,728
Trust units issued	5,566,000	74,863
Trust unit issuance costs (net of tax)	-	(3,163)
Trust units issued pursuant to DRIP	461,516	6,250
Trust units issued pursuant to OTUPP	992,548	13,352
Balance, September 30, 2010	**122,136,678**	**594,437**

Units Issued
On April 27, 2010, Peyto closed an offering of 5,566,000 trust units at a price of $13.45 per trust unit, receiving proceeds of $71.7 million (net of issuance costs).

On June 26, 2009, Peyto closed an offering of 9,000,000 trust units at a price of $10.50 per trust unit, receiving net proceeds of $90.2 million (net of issuance costs).

On December 31, 2009 the Trust completed a private placement of 196,420 trust units to employees and consultants for net proceeds of $2.7 million ($13.89 per unit). These trust units were issued on January 6, 2010.

Peyto reinstated its amended distribution reinvestment and optional trust unit purchase plan (the "Amended DRIP Plan") effective with the January 2010 distribution whereby eligible unitholders may elect to reinvest their monthly cash distributions in additional trust units at a 5% discount to market price. The DRIP plan incorporates an Optional Trust Unit Purchase Plan ("OTUPP") which provides unitholders enrolled in the DRIP with the opportunity to purchase additional trust units from treasury using the same pricing as the DRIP.

Units to be Issued
Subsequent to September 30, 2010, 444,558 trust units (64,677 pursuant to the DRIP and 379,881 pursuant to the OTUPP) were issued for net proceeds of $6.1 million. Subsequent to the issuance of these units, 122,581,236 trust units were outstanding.

Per Unit Amounts
Earnings per unit have been calculated based upon the weighted average number of units outstanding for three months ended September 30, 2010 of 121,765,712 (2009 – 114,920,194) and for the nine months ended September 30, 2010 of 118,803,946 (2009 – 109,085,029). There are no dilutive instruments outstanding.

7. Accumulated Distributions

The Trust declared total distributions to the unitholders in the aggregate amount of $43.9 million in the three months ended September 30, 2010 (2009 – total $41.4 million) and $129.0 million for the nine months ended September 30, 2010 (2009 - total $121.9 million) in accordance with the following schedule:

Production Period	Record Date	Distribution Date	Per Unit [1]
January 2010	January 31, 2010	February 15, 2010	$0.12
February 2010	February 28, 2010	March 15, 2010	$0.12
March 2010	March 31, 2010	April 15, 2010	$0.12
April 2010	April 30, 2010	May 14, 2010	$0.12
May 2010	May 31, 2010	June 15, 2010	$0.12
June 2010	June 30, 2010	July 15, 2010	$0.12
July 2010	July 31, 2010	August 13, 2010	$0.12
August 2010	August 31, 2010	September 15, 2010	$0.12
September 2010	September 30, 2010	October 31, 2010	$0.12

[1] Distributions per trust unit are the amounts declared monthly to unitholders.

Accumulated Earnings and Distributions

($000)	**September 30, 2010**	December 31, 2009
Accumulated earnings, beginning of period	**1,072,209**	919,435
Earnings for the period	**94,138**	152,774
Total accumulated earnings	**1,166,347**	1,072,209
Total accumulated distributions	**(1,101,428)**	(972,460)
Accumulated earnings, end of period	**64,919**	99,749

8. Operating Expenses

The Trust's operating expenses include all costs with respect to day-to-day well and facility operations. Processing and gathering income related to joint venture and third party natural gas reduces operating expenses.

	Three Months Ended Sept 30		**Nine Months Ended Sept 30**	
($000)	**2010**	2009	**2010**	2009
Field expenses	**7,055**	6,839	**21,565**	20,962
Processing and gathering income	**(2,593)**	(2,857)	**(7,931)**	(8,223)
Total operating costs	**4,462**	3,982	**13,634**	12,739

9. General and Administrative Expenses (G & A)

General and administrative expenses are reduced by operating and capital overhead recoveries on operated properties.

	Three Months Ended Sept 30		**Nine Months Ended Sept 30**	
($000)	**2010**	2009	**2010**	2009
General and administrative expenses	**2,507**	2,343	**7,243**	7,351
Overhead recoveries	**(983)**	(825)	**(2,809)**	(1,691)
Net general and administrative expenses	**1,524**	1,518	**4,434**	5,660

10. Financial Instruments and Risk Management

Financial Instrument Classification and Measurement

Financial instruments of the Trust carried on the Consolidated Balance Sheet are carried at amortized cost with the exception of cash and financial derivative instruments, specifically fixed price contracts, which are carried at fair value. There are no significant differences between the carrying value of financial instruments and their estimated fair values as at September 30, 2010.

The fair value of the Trust's cash and financial derivative instruments are quoted in active markets. The Trust classifies the fair value of these transactions according to the following hierarchy.

- *Level 1* – quoted prices in active markets for identical financial instruments.
- *Level 2* – quoted prices for similar instruments in active markets; quoted prices for identical or similar instruments in markets that are not active; and model-derived valuations in which all significant inputs and significant value drivers are observable in active markets.
- *Level 3* – valuations derived from valuation techniques in which one or more significant inputs or significant value drivers are unobservable.

The Trust's cash and financial derivative instruments have been assessed on the fair value hierarchy described above and classified as Level 1.

Fair Values of Financial Assets and Liabilities

The Trust's financial instruments include cash, accounts receivable, financial derivative instruments, due from private placement, current liabilities (excluding future income tax), provision for future performance based compensation and long term debt. At September 30, 2010, the carrying value of cash and financial derivative instruments are carried at fair value. Accounts receivable, due from private placement, current liabilities (excluding future income tax) and provision for future performance based compensation approximate their fair value due to their short term nature. The carrying value of the long term debt approximates its fair value due to the floating rate of interest charged under the credit facility.

Market Risk

Market risk is the risk that changes in market prices will affect the Trust's earnings or the value of its financial instruments. Market risk is comprised of commodity price risk, currency risk and interest rate risk. The objective of market risk management is to manage and control exposures within acceptable limits, while maximizing returns. The Trust's objectives, processes and policies for managing market risks have not changed from the previous year.

Commodity Price Risk Management

The Trust is a party to certain derivative financial instruments, including fixed price contracts. The Trust enters into these contracts with companies the Trust considers to be well established counterparties for the purpose of protecting a portion of its future earnings and cash flows from operations from the volatility of commodity prices. The Trust believes the derivative financial instruments are effective as hedges, both at inception and over the term of the instrument, as the term and notional amount do not exceed the Trust's firm commitment or forecasted transaction and the underlying basis of the instrument correlates highly with the Trust's exposure. A summary of contracts outstanding in respect of the hedging activities at September 30, 2010 are as follows:

Description ($000 except per GJ amounts)	**Notional (1)**	**Term**	**Effective Rate**	**Fair Value Level**	**Asset as at September 30, 2010**	**Asset as at December 31, 2009**
Natural gas financial swaps - AECO	23.28GJ (2)	2010- 2012	$5.07/GJ	Level 1	41,514	$9,936

(1) Notional values as at September 30, 2010 (2) Millions of gigajoules

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
November 1 , 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.20/GJ
November 1 , 2009 to October 31, 2010	Fixed price	5,000 GJ	$5.00/GJ
November 1, 2009 to March 31, 2011	Fixed Price	5,000 GJ	$6.20/GJ
November 1 , 2009 to March 31, 2011	Fixed price	5,000 GJ	$5.81/GJ
April 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$6.10/GJ
April 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$5.50/GJ

April 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$4.50/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.28/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.29/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.555/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$5.70/GJ
April 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$4.55/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$5.67/GJ
April 1, 2010 to March 31, 2012	Fixed Price	5,000 GJ	$5.82/GJ
Ju.ly 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$4.03/GJ
Ju.ly 1, 2010 to October 31, 2010	Fixed Price	5,000 GJ	$4.20/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$8.91/GJ
November 1, 2010 to March 31, 2011	Fixed Price	5,000 GJ	$9.15/GJ
April 1 , 2011 to March 31, 2012	Fixed Price	5,000 GJ	$6.20/GJ
April 1 , 2011 to March 31, 2012	Fixed Price	5,000 GJ	$5.00/GJ
April 1 , 2011 to March 31, 2012	Fixed Price	5,000 GJ	$5.12/GJ
November 1, 2011 to March 31, 2012	Fixed Price	5,000 GJ	$4.50/GJ

As at September 30, 2010, the Trust had committed to the future sale of 23,280,000 gigajoules (GJ) of natural gas at an average price of $5.07 per GJ or $5.93 per mcf. Had these contracts been closed on September 30, 2010, the Trust would have realized a gain in the amount of $41.5 million. If the AECO gas price on September 30, 2010 were to increase by $1/GJ, the unrealized gain on these closed contracts would change by approximately $23.3 million. An opposite change in commodity prices rates will result in an opposite impact on earnings which would have been reflected in the other comprehensive income of the Trust.

Subsequent to September 30, 2010 the Trust entered into the following contracts:

Natural Gas Period Hedged	**Type**	**Daily Volume**	**Price (CAD)**
April 1, 2011 to October 31, 2012	Fixed Price	5,000 GJ	$4.05/GJ

Interest rate risk
The Trust is exposed to interest rate risk in relation to interest expense on its revolving credit facility. Currently, the Trust has not entered into any agreements to manage this risk. If interest rates applicable to floating rate debt were to have increased by 100 bps (1%) it is estimated that the Trust's earnings for the three and nine month periods ended September 30, 2010 would decrease by $1.1 million and $3.2 million respectively. An opposite change in interest rates will result in an opposite impact on earnings.

Credit Risk
A substantial portion of the Trust's accounts receivable is with petroleum and natural gas marketing entities.

Industry standard dictates that commodity sales are settled on the 25th day of the month following the month of production. The Trust generally extends unsecured credit to these companies, and therefore, the collection of accounts receivable may be affected by changes in economic or other conditions and may accordingly impact the Trust's overall credit risk. Management believes the risk is mitigated by the size, reputation and diversified nature of the companies to which they extend credit. The Trust has not previously experienced any material credit losses on the collection of accounts receivable. Of the Trust's individually significant accounts receivable for the period ended September 30, 2010, approximately 13% was due from one company (September 30, 2009 – 10%, one company). Of the Trust's revenue for the nine months ended September 30, 2010, approximately 94% was received from six companies (23%, 19%, 16%, 13%, 12% and 11%) (September 30, 2009 – 86%, four companies (31%, 25%, 19% and 11%)). The maximum exposure to credit risk is represented by the carrying amount on the balance sheet. There are no material financial assets that the Trust considers past due and no accounts have been written off.

The Trust may be exposed to certain losses in the event of non-performance by counterparties to commodity price contracts. The Trust mitigates this risk by entering into transactions with counter-parties that have investment grade credit ratings, in accordance with policy as established by the

Board of Directors. Counterparties for derivative instrument transactions are limited to financial institutions which are all members of our syndicated credit facility.

The Trust assesses quarterly if there should be any impairment of financial assets. At September 30, 2010, there was no impairment of any of the financial assets of the Trust.

Liquidity Risk
Liquidity risk includes the risk that, as a result of operational liquidity requirements:

- The Trust will not have sufficient funds to settle a transaction on the due date;
- The Trust will be forced to sell financial assets at a value which is less than what they are worth; or
- The Trust may be unable to settle or recover a financial asset at all.

The Trust's operating cash requirements, including amounts projected to complete our existing capital expenditure program, are continuously monitored and adjusted as input variables change. These variables include, but are not limited to, available bank lines, oil and natural gas production from existing wells, results from new wells drilled, commodity prices, cost overruns on capital projects and changes to government regulations relating to prices, taxes, royalties, land tenure, allowable production and availability of markets. As these variables change, liquidity risks may necessitate the need for the Trust to conduct equity issues or obtain project debt financing.

The following are the contractual maturities of financial liabilities as at September 30, 2010:

($000s)	**<1 Year**	**1-2 Years**	**2-5 Years**	**Thereafter**
Accounts payable and accrued liabilities	55,546			
Distributions payable	14,656			
Provision for future performance based compensation	11,486	2,990		
Long-term debt[1]		455,000		

[1]Revolving credit facility renewed annually (see Note 5)

11. Capital Disclosures

The Trust's objectives when managing capital are: (i) to maintain a flexible capital structure, which optimizes the cost of capital at acceptable risk; and (ii) to maintain investor, creditor and market confidence to sustain the future development of the business.

The Trust manages its capital structure and makes adjustments to it in light of changes in economic conditions and the risk characteristics of our underlying assets. The Trust considers its capital structure to include unitholders' equity, debt and working capital. To maintain or adjust the capital structure, the Trust may from time to time, issue trust units, raise debt and/or adjust its capital spending to manage its current and projected debt levels. The Trust monitors capital based on the following non-GAAP measures: current and projected debt to earnings before interest, taxes, depreciation, depletion and amortization ("EBITDA") ratios, payout ratios and net debt levels. To facilitate the management of these ratios, the Trust prepares annual budgets, which are updated depending on varying factors such as general market conditions and successful capital deployment. Currently, all ratios are within acceptable parameters. The annual budget is approved by the Board of Directors. The Trust's unitholders' capital is not subject to any external financial covenants.

There were no changes in the Trust's approach to capital management from the previous year.

($000)	**September 30, 2010**	December 31, 2009
Unitholders' equity	**699,576**	612,483
Long-term debt	**455,000**	435,000
Working capital (surplus) deficit [1]	**(20,954)**	(1,822)
	1,133,622	1,045,661

[1]Current liabilities less current assets (includes unrealized hedging asset of $35.4 million (2009 – $8.7 million)

12. Supplemental Cash Flow Information

($000)	Three Months Ended Sept 30 2010	2009	Nine Months Ended Sept 30 2010	2009
Cash interest paid during the period	**5,136**	4,493	**14,517**	11,919

13. Contingencies and Commitments

Following is a summary of the Trust's commitments related to operating leases as at September 30, 2010. The Trust has no other contractual obligations or commitments as at September 30, 2010.

($000)	September 30, 2010
2010	260
2011	1,043
2012	1,043
2013	1,043
2014	1,043
	4,432

Contingent Liability

From time to time, Peyto is the subject of litigation arising out of its day-to-day operations. Damages claimed pursuant to such litigation, may be material or may be indeterminate and the outcome of such litigation may materially impact Peyto's financial position or results of operations in the period of settlement. While Peyto assesses the merits of each lawsuit and defends itself accordingly, Peyto may be required to incur significant expenses or devote significant resources to defending itself against such litigation. These claims are not currently expected to have a material impact on Peyto's financial position or results of operations.

14. Subsequent Events

On November 1, 2010, the Board of Directors of Peyto Energy Administration Corp. unanimously resolved to approve the conversion of the Trust to a corporation effective December 31, 2010, pending Unitholder approval on December 8, 2010.

Peyto Exploration & Development Corp. Information

Officers

Darren Gee
President and Chief Executive Officer

Scott Robinson
Executive Vice-President and Chief Operating Officer

Kathy Turgeon
Vice-President, Finance and Chief Financial Officer

Glenn Booth
Vice-President, Land

David Thomas
Vice-President, Exploration

Stephen Chetner
Corporate Secretary

Directors
Don Gray, Chairman
Rick Braund
Stephen Chetner
Brian Davis
Michael MacBean, Lead Independent Director
Darren Gee
Gregory Fletcher
Scott Robinson

Auditors
Deloitte & Touche LLP

Solicitors
Burnet, Duckworth & Palmer LLP

Bankers
Bank of Montreal
Union Bank, Canada Branch
BNP Paribas (Canada)
Royal Bank of Canada
Canadian Imperial Bank of Commerce
Alberta Treasury Branches
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